AR72

2001 Annual Report

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DELIBERATE STRIDES TO GROWTH



PETRO-CANADA

HIGHLIGHTS

(stated in millions of Canadian dollars, unless otherwise indicated)	2001	2000	1999
FINANCIAL			
Earnings from operations (in 2000, before reorganization costs)	**874**	860	236
Net earnings	**904**	893	233
Cash flow	**1 688**	1 870	964
Per share (dollars)			
Earnings from operations (in 2000, before reorganization costs)	**3.30**	3.16	0.87
Net earnings — basic	**3.41**	3.28	0.86
Net earnings — diluted	**3.38**	3.25	0.85
Cash flow	**6.37**	6.87	3.55
Dividends	**0.40**	0.40	0.34
Expenditures on property, plant and equipment and exploration	**1 681**	1 203	1 021
Return on capital employed (per cent)	**15.7**	16.6	5.6
Operating return on capital employed (per cent) (in 2000, before reorganization costs)	**15.2**	16.0	5.6
Debt	**1 401**	1 774	1 711
Debt to debt plus equity (per cent)	**21.7**	27.9	29.5
Debt to cash flow (times)	**0.8**	0.9	1.8
OPERATING			
Total production (thousands of barrels of oil equivalent per day)[1]	**196.5**	212.2	215.1
Crude oil and field natural gas liquids production, Net before royalties (thousands of barrels per day)	**77.4**	89.2	95.3
Natural gas production, net before royalties, Excluding injectants (millions of cubic feet per day)	**714**	738	719
Proved oil and field natural gas liquids reserves, Net before royalties (millions of barrels)	**450**	414	476
Proved natural gas reserves, net before royalties (trillions of cubic feet)	**2.2**	2.3	2.5
Refined petroleum product sales (thousands of cubic metres per day)	**54.5**	55.4	51.2
Refinery crude capacity utilization (per cent)	**96**	101	100

1 Natural gas production (excluding injectants) is converted using 6 000 cubic feet of gas for one barrel of oil.

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FRONT COVER PHOTO:
The Terra Nova Floating Production Storage and Offloading (FPSO) vessel sailing to its location 350 kilometres east of Newfoundland.

BUILDING A SOLID PLATFORM FOR LONG-TERM GROWTH

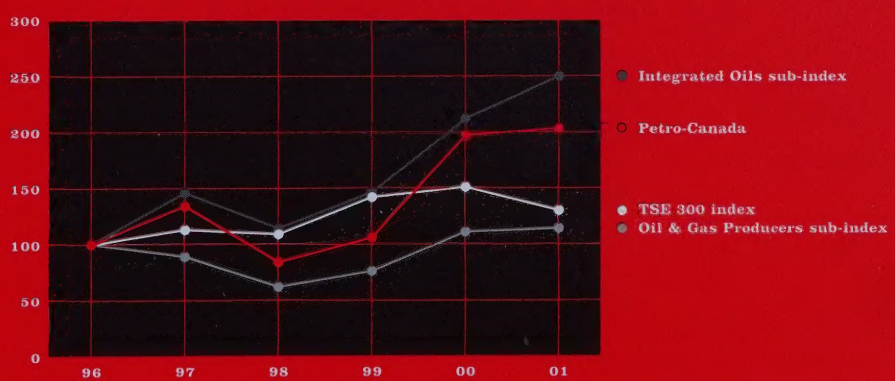
Strategically focused, financially capable and disciplined in execution, Petro-Canada delivered strong results in 2001. Our core businesses are poised to provide profitable growth in the years ahead as large development projects such as Terra Nova *(cover photo)* come on stream.

Our positioning for a world-class future was enhanced early in 2002 with our agreement to acquire the upstream operations of Veba Oil & Gas GmbH, establishing International as our fifth core business.

Petro-Canada's offshore oil projects, oil sands developments, strength in natural gas, refining, marketing and lubricants, and our international expansion offer investors visible strides to long-term growth.

FIVE-YEAR SHARE PRICE PERFORMANCE

Petro-Canada shares rose 103 per cent from year-end 1996 through 2001, reflecting the company's goal of creating shareholder value.



(December 31, 1996 = 100)

Changes in yearly closing values for Petro-Canada shares compared with the Toronto Stock Exchange (TSE) 300 index, the TSE Integrated Oils sub-index and the TSE Oil & Gas Producers sub-index.

CORE BUSINESSES AT A GLANCE

Petro-Canada is strategically focused on five core businesses:

EAST COAST OFFSHORE



Hibernia

Business Description

- Explores for, develops, produces and markets oil from offshore Newfoundland
- 20% interest in the producing Hibernia oil field
- 34% interest in, and operator of, the Terra Nova oil field
- Interests in other significant discoveries and exploration acreage

Strategies

- Expand light oil production base from offshore Newfoundland, capitalizing on experience gained in developing the Hibernia and Terra Nova oil fields
- Pursue high-potential exploration plays

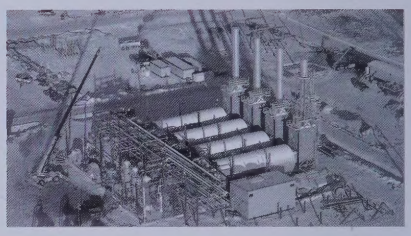
2001 Achievements

- Strong operating performance at Hibernia increased Petro-Canada's share of production to a record 29 700 barrels per day
- Successfully drilled seven new wells at Hibernia, including two in the Avalon formation
- Terra Nova Floating Production Storage and Offloading (FPSO) vessel commissioned with first oil shipped late January 2002
- Confirmed oil on the previously undrilled Far East block at Terra Nova
- Received regulatory approval for White Rose project
- Secured new exploration acreage for the sixth consecutive year

Plans For 2002

- Maintain strong performance from Hibernia with sustained production reaching 32 000 barrels per day net to Petro-Canada by the end of 2002
- Achieve sustainable Terra Nova production of 42 500 barrels per day net to Petro-Canada by year-end
- Evaluate Far East economic potential with a second well possibly in late 2002 or 2003
- Secure rig to drill first Flemish Pass well in late 2002 or 2003
- Reach decision, with co-owner, on whether to proceed with White Rose oil field development

OIL SANDS



MacKay River construction

Business Description

- 12% working interest in the Syncrude oil sands mining operation
- 100% working interest in the MacKay River *in situ* oil sands development
- Interests in more than 300 000 net acres of prospective *in situ* oil sands leases
- Evaluating feed conversion at the Edmonton refinery to integrate *in situ* production with refining

Strategies

- Increase share of Syncrude production to over 40 000 barrels per day by 2005 and participate in further expansions
- Phased development of oil sands properties so we can benefit from learnings and respond to evolving market conditions
- Pursue *in situ* oil sands developments and integration with our Edmonton refinery

2001 Achievements

- Petro-Canada's share of Syncrude production averaged 26 800 barrels per day
- Commenced third phase of Syncrude expansion
- Continued development and construction of the 30 000 b/d MacKay River project
- Began third-party construction of pipeline to take MacKay River production to markets
- Reached agreement for third-party construction of a 165 megawatt MacKay River co-generation plant
- Submitted regulatory application for 80 000 b/d Meadow Creek *in situ* project
- Submitted regulatory application for feed conversion at Edmonton refinery

Plans For 2002

- Participate in Syncrude Stage 3 expansion (upgrader expansion and second train at Aurora mine)
- Complete production facilities and pipeline at MacKay River, commence reservoir steaming in the third quarter and bitumen production by year-end
- Continue Meadow Creek preparations
- Complete design and begin engineering for feed conversion

NORTH AMERICAN NATURAL GAS



Foothills exploration

Business Description

- Explores for, produces and markets natural gas and associated liquids
- Among the largest producers in Western Canada
- Exploring in the Alberta Foothills, northeastern British Columbia, the Mackenzie Delta and offshore Nova Scotia

Strategies

- Maximize profitability in Western Canada through focused exploration and development in our core areas — the Alberta Foothills, northeastern British Columbia, west-central and southeastern Alberta
- Pursue high-potential exploration plays in the Mackenzie Delta and offshore Nova Scotia

2001 Achievements

- Gas production averaged 714 million cubic feet per day despite sales of non-core properties
- Natural gas liquids production averaged 11 100 barrels per day
- Added 269 billion cubic feet of proved reserves through the drill bit, replacing 103% of 2001 production
- Achieved finding and development costs of $1.52 per thousand cubic feet of gas equivalent
- Continued exploration and development success in the Alberta Foothills
- Drilled first well, spudded second well and completed extensive seismic programs in the Mackenzie Delta
- Acquired exploration acreage in Alaska with similar geological characteristics to the Alberta Foothills
- Secured new exploration acreage on the Scotian Shelf

Plans For 2002

- Maintain active drilling programs in the Alberta Foothills, northeastern B.C., west-central and southeastern Alberta
- Test the Kurk well, drill three additional wells and shoot 2-D and 3-D seismic in the Mackenzie Delta
- Secure rig to drill well on the Scotian Shelf in 2002 or 2003

DOWNSTREAM



Canada's Gas Station

Business Description

- Converts crude oil into refined products, including gasoline, diesel, lubricants and asphalt
- Operates three refineries, representing 18% of Canada's refining capacity
- Markets refined petroleum products and services through a nationwide network of retail and wholesale outlets
- Canada's second largest marketer of refined petroleum products, with a 17% share of market
- Manufactures and markets high-quality specialty lubricants

Strategies

- Generate superior returns and growth by focusing on first-quartile refining performance, building on our strength in niche markets, being the brand of choice for Canadian gasoline consumers, and increasing sales of high-margin specialty lubricants

2001 Achievements

- Converted 63 company-owned retail sites to the new image
- Achieved throughput per retail site of 3.8 million litres
- Increased sales from non-petroleum products and services by 15%
- Despite a weakening economy, asphalt sales reached 1.5 billion litres
- With increased refinery turnarounds, achieved refinery utilization of 96%
- Increased sales of high-margin lubricants by 15% with penetration into new high-value automotive applications

Plans For 2002

- Narrow the gap on first-quartile refining performance, and improve refinery reliability and utilization
- Continue refinery modifications to meet future environmental regulations for fuels
- Continue to accelerate roll-out of new-image retail sites and increase sales of non-petroleum products and services
- Further increase lubricant sales into higher-margin markets

INTERNATIONAL



Algerian operations

Business Description

- In January 2002, Petro-Canada agreed to acquire the upstream operations of Veba Oil & Gas GmbH, a European-based exploration and production company, solidly establishing International as our fifth core business and a platform for long-term growth
- Veba's production and exploration interests are focused in three regions: the North Sea, North Africa, and northern Latin America
- Petro-Canada has existing North African operations in Libya, Algeria and Tunisia

Strategies

- Achieve sustained material growth through acquisition of sizeable assets that are concentrated in selected geographic areas and fit well with Petro-Canada's strength and expertise

2001 Achievements

- Petro-Canada purchased the interest of Lundin AB of Sweden in the En Naga block in Libya
- In the En Naga project in Libya, three of the initial five wells were completed. Construction of processing facilities and a pipeline proceeded on schedule
- Production in Algeria (before royalties and the sharing of profit oil) averaged 2 300 barrels per day in 2001. An exploration well was spudded in January 2002
- In Tunisia, completed a 2-D seismic program

Plans For 2002

- The Veba acquisition will close in stages during 2002
- In the En Naga project in Libya, initial gross production of 14 000 barrels per day (before production sharing with the National Oil Corporation) is expected by mid-2002
- Petro-Canada will aggressively pursue medium-term development as well as longer-term growth opportunities within the Veba assets

TO OUR SHAREHOLDERS

Petro-Canada delivered record net earnings of $904 million in 2001, driven by an unusually positive business environment in the early part of the year and by our actions to boost profitability through strategic focus and disciplined execution. At the same time, we took deliberate strides to deliver sustained growth.

Early in 2001, we completed our program of divesting non-core and non-value-adding assets. And we made solid progress in our drive to first-quartile performance by improving reliability and cost management. Thanks to the diligence of our employees in a favourable environment, we delivered returns exceeding the cost of capital in each of our core businesses, and positioned each to add shareholder value over the long term.

Our North American Natural Gas business maintained competitive finding and development cost performance and delivered daily production of 714 million cubic feet per day. That was down only three per cent from 2000 despite the sale of non-core and higher-cost production. Reserve additions more than replaced production. We continued our exploration program for major new gas reserves in the Mackenzie Delta and offshore Nova Scotia, and added a land position in Alaska.

The East Coast Offshore business saw increased production from the Hibernia oil field, and completed construction and commissioning to bring the Petro-Canada operated Terra Nova oil field on stream in January 2002. At full production, Terra Nova is expected to provide more than 40 000 barrels a day to Petro-Canada. We expect to decide on proceeding with the next development — White Rose — by mid-year 2002, and we are planning exploration on several blocks of land in deeper waters off Newfoundland.

Our Oil Sands business expects strong growth from an integrated strategy that will produce and refine bitumen to finished products. Significant production increments are expected over the coming years, from both the Syncrude expansion and our operated *in situ* bitumen developments. Our first 30 000 barrel per day *in situ* plant is nearing completion at MacKay River, with initial production expected at the end of 2002. We have filed an application for an 80 000 barrel per day development at Meadow Creek (60 000 barrels per day net to Petro-Canada) and for the conversion of our Edmonton refinery to process bitumen. Integrating our bitumen development with our Edmonton refinery will capture value from wellhead to fuel pump.

The Downstream business delivered record earnings through a significant improvement in margins, strong retail sales, growth in non-petroleum products and services and higher premium-market lubricants sales. We focused on refinery reliability and costs, we saw a turnaround in the profitability of the lubricants business, and we continued to roll out our new-image retail outlets. Marketing increased sales and earnings despite the economic downturn. A strike at several facilities in 2001 delayed some of our cost initiatives, but the agreement we reached establishes a firm base for a first quartile cost structure. Non-union staff did a tremendous job efficiently operating our plants in a safe manner through the labour disruption.

Our goal remains to consistently add shareholder value. An aggressive capital investment program in 2001 directed nearly $1.7 billion to our base businesses and known growth opportunities, largely in Canada. At the same time, with high commodity prices generating strong cash flow and our shares undervalued, we repurchased about 3.5 per cent of our outstanding shares through a buyback program, adding value for continuing shareholders.

With a solid base in our four core businesses, early last year we began to look at longer-term sources of growth for the company. Petro-Canada is well positioned in virtually every producing and exploration area in Canada, and has an impressive portfolio of projects over the next several years. But growth beyond that was highly dependent on exploration success off the East Coast and on the timing of gas coming out of the Mackenzie Delta. To provide a more certain future, the Executive Leadership Team developed a strategy to establish International as a fifth core business and a platform for long-term growth.

The basic strategy was to build this business over time, with a geographic focus starting in North Africa where we already had a presence, and growing through



"Petro-Canada is taking deliberate strides to growth, and continually adding to shareholder value. We are focused on businesses in areas where we can be world-class competitors, and we have the capability and the discipline to deliver on shareholder expectations."

Ron Brenneman, *Chief Executive Officer*

asset acquisitions and concentric exploration. At the same time, we were aware that a larger acquisition could possibly accelerate all or part of our strategy with a much higher chance of success. A number of candidates were evaluated.

When the upstream assets of Veba Oil & Gas came on the market, we saw the opportunity to acquire a going concern with quality assets, geographic focus in three key regions, an experienced organization and established relationships with host countries.

The acquisition meets our objective of providing a solid platform for long-term growth and adds significant up-front shareholder value. It will raise our total upstream production by over 75 per cent and proved reserves by over 70 per cent, subject to parties exercising rights of first refusal. No new equity will be issued in the transaction, so earnings and cash flow per share will rise. The asset portfolio holds significant potential for medium-term, low-risk production development with modest capital requirements, as well as longer-term growth through exploration and entry projects in new, promising areas.

We expect most of the transaction to close in the spring of 2002, with some components closing later in the year. A veteran Petro-Canada executive, Norm McIntyre, appointed President in January 2002, will integrate and lead our International business.

While International is an important step for us, we continue to be fully committed to our four existing core businesses. We are demonstrating our confidence in their potential by budgeting $1.8 billion in capital expenditures for the ongoing business in 2002, excluding requirements for the acquired Veba assets. Canada will remain the heart of our business, even as we diversify our opportunities internationally. Similarly, we will maintain our commitment to environmental responsibility, integrity, community investment and employee well-being.

Petro-Canada is taking deliberate strides to growth, and continually adding to shareholder value. We are focused on businesses in areas where we can be world-class competitors, and we have the capability and the discipline to deliver on shareholder expectations.

In closing, on behalf of the Executive Leadership Team I would like to pay tribute to Petro-Canada's employees. Their efforts during a year of challenges — including maintaining operations through labour disruptions in the Downstream, the drive to start up Terra Nova, and the work required to achieve the Veba acquisition — were critical to continuing the growth and progress of our company.

Following the agreement to acquire the Veba operations, we broadened our Executive Leadership Team to include the leaders of all five core businesses as well as Finance, creating a strong and experienced executive team to lead Petro-Canada into our exciting — and expanded — future.



Ron Brenneman
Chief Executive Officer

MANAGEMENT'S DISCUSSION & ANALYSIS

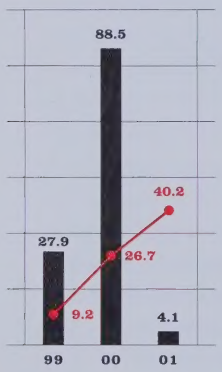
Management's Discussion and Analysis (MD&A) should be read in conjunction with the Financial Statements and Notes included in this report. Graphs accompanying the text identify our 'value drivers', key measures of performance in each component of our business.

RESULTS OF OPERATIONS

Summarized Financial Results

SHAREHOLDER VALUE

Shareholder value grew 4.1 per cent through market appreciation and dividends.



■ One-year return *(per cent)*

● Three-year average return *(per cent)*

– Shareholder value measures the change in the Petro-Canada share price plus dividend returns.

Consolidated Financial Results

(millions of dollars, unless otherwise indicated)	**2001**	2000	1999
Earnings from operations[1]	**874**	860	236
Reorganization costs	**—**	(38)	—
Gain (loss) on sale of assets	**30**	71	(3)
Net earnings	**904**	893	233
Earnings per share[2] (dollars) — basic	**3.41**	3.28	0.86
— diluted	**3.38**	3.25	0.85
Cash flow[3]	**1 688**	1 870	964
Cash flow per share (dollars)	**6.37**	6.87	3.55
Average capital employed	**6 255**	5 884	5 630
Return on capital employed (per cent)	**15.7**	16.6	5.6
Operating return on capital employed[1] (per cent)	**15.2**	16.0	5.6
Return on equity (per cent)	**18.7**	21.0	5.8
Debt	**1 401**	1 774	1 711
Cash and short-term investments	**781**	1 415	206

1 Before reorganization costs in 2000.
2 Effective January 1, 2001, the Company adopted the recommendations of the Canadian Institute of Chartered Accountants on accounting for earnings per share.
3 Before changes in non-cash working capital items.

This MD&A contains forward-looking statements, including, but not limited to, references to: future capital and other expenditures (including the amount, nature and sources of funding thereof), oil and gas production levels and the sources of their growth, tax and royalty rates, oil and gas prices, the Canadian dollar exchange rate, interest rates, refining and marketing margins, demand for refined petroleum products, planned facilities construction and expansion, retail site throughputs, pre-production and operating costs, proved reserves, natural gas export capacity, results of exploration and development activities, acquisition and disposition of resource properties and the dates by which certain areas will be developed or will come on-stream. These forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; refining and marketing margins; the ability to produce and transport crude oil and natural gas to markets; the results of exploration and development drilling and related activities; fluctuation in foreign currency exchange rates and interest rates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; changes in environmental and other regulations; risks attendant with oil and gas operations; and other factors, many of which are beyond the control of Petro-Canada.

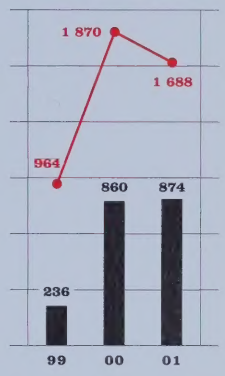
2001 Compared with 2000

Solid financial performance from all business units raised net earnings in 2001 to a record level. Volume gains from core producing properties, higher natural gas prices, wide refining margins for a large part of the year, and lower income taxes were key contributors to strong financial results. The decline in return on capital employed, to 15.7 per cent from 16.6 per cent, reflects Petro-Canada's increasing investments in major projects such as Terra Nova, which have yet to contribute to earnings. A drop in cash flow from the exceptionally high $1 870 million achieved in 2000 mainly resulted from a $165 million increase in the current portion of the provision for income taxes.

Earnings from operations rose to $874 million in 2001, up from $860 million before reorganization costs of $38 million in 2000, as higher Downstream earnings and a reduction in the net cost of Shared Services outweighed lower earnings in the Upstream. Marked improvements in Lubricants and Marketing, combined with strong refining margins and wide light/heavy crude oil price differentials, were key to the rise in Downstream earnings. Petro-Canada enjoys a significant benefit from light/heavy price spreads as we are able to process a relatively high proportion of heavy crude in our refinery feedstock mix. The decline in the Upstream reflected the sale of non-strategic producing assets over the past two years, higher exploration expense and lower oil prices, with a partial offset from higher prices for natural gas and a reduction in income taxes.

OPERATING EARNINGS AND CASH FLOW

A new record was established for operating earnings.



■ Earnings from operations *($ millions)*

● Cash flow *($ millions)*

– 2000 earnings are before reorganization costs.

Quarterly Financial Information

(See page 45 of the 2001 Annual Report for summarized 2000 and 2001 quarterly financial results.)

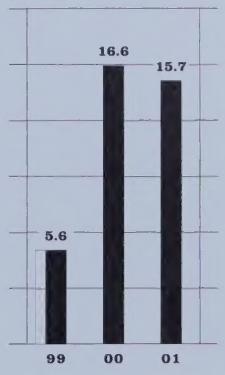
In the fourth quarter of 2001, operating earnings were $71 million, down from $287 million before reorganization costs in the same period of 2000. Net earnings were $71 million, compared with $386 million in the same period a year ago, when Petro-Canada recorded a $104 million after-tax gain from the sale of assets. Cash flow was $307 million, compared with $684 million.

Upstream earnings from operations in the fourth quarter of 2001 were $52 million, down from $244 million in the fourth quarter of 2000, largely due to lower prices for natural gas and oil. Downstream earnings from operations were $48 million, down from $66 million, mainly as the result of lower refining margins.

As a consequence of Enron Corporation's bankruptcy filing in the fourth quarter of 2001, natural gas purchase and sale agreements between Petro-Canada and the Enron group of companies were terminated. Petro-Canada made a one-time provision for outstanding receivables that adversely affected net earnings in the quarter by approximately $15 million after tax. Petro-Canada does not expect any further negative impact related to Enron.

RETURN ON CAPITAL EMPLOYED

Return on capital employed benefited from strong earnings.



■ Return on capital employed *(per cent)*

Business Conditions

Petro-Canada's Upstream financial results are significantly influenced by crude oil and natural gas prices, the Canadian/U.S. dollar exchange rate, and demand for natural gas. Downstream results are influenced primarily by the level and volatility of crude oil prices, industry refining margins, movements in light/heavy crude oil price differentials, demand for refined petroleum products and the degree of market competition.

Business Conditions in 2001

Oil and gas prices declined from exceptional highs at the beginning of 2001 to end the year close to their long-term historical averages. A slowdown in global economic activity that became increasingly evident as the year progressed was the major reason for the declines, particularly for crude oil. For natural gas, the combination of weak demand and increased deliverability across North America, resulting from expanded drilling activity, led to a substantial build-up of working gas in storage and caused natural gas prices to fall sharply in the second half of the year. The terrorist attacks in the United States on September 11 exacerbated the economic downturn and soft market conditions for both oil and gas.

On the New York Mercantile Exchange (NYMEX), the price of benchmark West Texas Intermediate (WTI) crude oil averaged U.S.$25.90/bbl in 2001, down 14 per cent from U.S.$30.20/bbl in the previous year. At year-end 2001, WTI stood at U.S.$19.84/bbl, compared with U.S.$26.80/bbl at the end of 2000. The impact of declining international oil prices on Canadian crude prices was partially offset by the continued weakness in the Canadian dollar relative to the U.S. currency. The Canadian dollar exchange rate averaged 64.6 U.S. cents in 2001, a four per cent decline from 67.4 U.S. cents in the previous year. After hitting a record low of 62.4 U.S. cents on November 9, 2001, the rate fluctuated below 64.0 U.S. cents before closing the year at 62.8 U.S. cents. Petro-Canada's posted prices for benchmark Edmonton Light crude oil averaged $39.58/bbl during 2001, down $5.17/bbl, or almost 12 per cent, from the level posted in 2000.

The average NYMEX price for natural gas at the Henry Hub in Louisiana peaked at U.S.$9.82 per million British thermal units (MMBTU) on January 9, 2001, declined to a low of U.S.$1.83 by September 26 and closed the year at U.S.$2.57/MMBTU. The average price at Henry Hub increased 12 per cent to U.S.$4.38/MMBTU in 2001 from U.S.$3.91 in 2000. The Henry Hub-AECO-C differential averaged U.S.$0.27/MMBTU in 2001 compared with U.S.$0.54 in 2000. The average gas price at the AECO-C Hub in Alberta rose to $6.57 per thousand cubic feet (mcf), up 26 per cent from $5.24 in 2000. At year-end 2001, the AECO-C Hub stood at $3.90/mcf.

During the first half of 2001, the downstream business environment was characterized by strong refining margins and wide light/heavy oil price differentials. During the latter part of the year, as the slowdown in economic activity became more entrenched, demand for petroleum products weakened, refining margins softened and, as oil prices fell, crude price differentials narrowed. The New York Harbor 3-2-1 crack spread, a benchmark indicator of the margin available to refiners, averaged U.S.$4.44/bbl in 2001, down 20 per cent from U.S.$5.53/bbl in 2000. The crude oil price differential between benchmark North Sea Brent (light) and Mexican Maya (heavy) averaged U.S.$7.31/bbl compared with U.S.$5.40/bbl in 2000. Based on Petro-Canada's posted prices, the average spread between the prices of Edmonton Light and Bow River (heavy) widened to $14.97/bbl, up 38 per cent from $10.88/bbl in 2000. The price differential between WTI and lower-priced North Sea Brent, which affects Petro-Canada's Montreal and Oakville refinery margins, averaged U.S.$1.44/bbl in 2001 compared with U.S.$1.81/bbl in the previous year.

Canadian refined petroleum product sales declined 0.8 per cent in 2001, compared with an increase of 1.5 per cent in 2000. The decline in 2001 reflected the increasing effects of the economic slowdown during the latter part of the year.

Outlook for Business Conditions in 2002

Supply and demand, weather, political events and the level of industry inventories are the key factors influencing prices for energy commodities. Given current worldwide political and economic uncertainties, Petro-Canada expects volatility and uncertainty in oil and gas prices to continue through 2002. Pending any resurgence in global demand and barring any major disruption to supply, crude oil prices are expected to remain under downward pressure. OPEC's ability to maintain production discipline among its members and the willingness of non-OPEC nations to commit and stand by their commitments on production cutbacks will be critical to price strength in 2002.

Natural gas prices across North America are expected to remain soft during 2002, as the industry ends the 2001/2002 heating season with very high inventories of natural gas, following one of the warmest winters on record. The high level of working gas in storage will reduce the need for gas injections to replenish storage levels before next winter, thereby weakening the support that natural gas prices typically get during spring and summer. The only factor likely to support gas prices this year is a much weaker outlook for production growth, due to the sharp slowdown in drilling activity and the cutback in exploration and development budgets in response to the soft prices that have prevailed since mid-2001.

In view of the current slowdown in economic activity across North America, little, if any, growth is anticipated in domestic sales of refined products in 2002, while refinery margins are expected to return to their long-term average.

Economic Sensitivities

The following table shows the estimated after-tax effects that changes in certain factors would have had on Petro-Canada's 2001 net earnings had these changes occurred. We base these calculations on business conditions, production and sales volumes realized in 2001.

Sensitivities Affecting Net Earnings

Factor	2001 Averages	Change (+/-)	Approximate Change (+/-) in Net Earnings[1] (millions of Canadian dollars)
Upstream Sector			
WTI benchmark crude oil price	U.S.$25.90/bbl	U.S.$1.00/bbl	24
Price received for natural gas	$6.00/mcf	$0.10/mcf	12
Production of crude oil and liquids	77 400 barrels per day (b/d)	1 000 b/d	2
Production of natural gas available for sale	714 million cubic feet per day (mmcf/d)	10 mmcf/d	3
Downstream Sector			
New York Harbor 3-2-1 cracking margin[2]	U.S.$4.44/bbl	U.S.$0.10/bbl	5
Light/heavy crude price differential[3]	$14.97/bbl	$1.00/bbl	11
Corporate			
Canadian dollar exchange rate ($U.S. per $Cdn.)[4]	U.S.$0.646	U.S.$0.01	(6)

1 The impact of a change in one factor may be compounded or offset by changes in other factors. This table does not consider the impact of any inter-relationship among the factors. The application of these factors may not necessarily lead to an accurate prediction of future results of operations. We may undertake risk management initiatives from time to time that affect these sensitivities.

2 New York Harbor 3-2-1 cracking margin applies mainly to Eastern Canada markets.

3 The spread between the prices of benchmark Edmonton Light and Bow River (heavy) crude oils.

4 A strengthening Canadian dollar versus the U.S. dollar has a negative effect on Petro-Canada's earnings.

Upstream Sector

Upstream Financial Results

(millions of dollars, unless otherwise indicated)	2001	2000	1999
Earnings from operations	**663**	704	243
Gain on sale of assets	**29**	72	6
Net earnings	**692**	776	249
Cash flow	**1 152**	1 538	885
Operating return on capital employed (per cent)	**20.9**	22.4	7.1
Average capital employed	**3 179**	3 146	3 416

2001 Compared with 2000

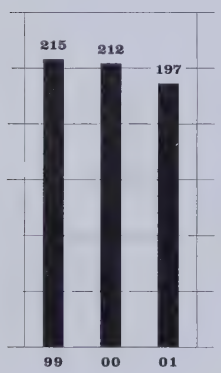
Upstream earnings from operations fell short of the record achieved in 2000 as production gains at Hibernia and Syncrude and higher prices for natural gas were more than offset by the sale of non-strategic producing assets and lower oil prices. A $119 million decline in the provision for income taxes was partly offset by a $74 million increase in exploration expense. The income tax decline resulted, in part, from tax rate reductions on future income taxes. A sharp increase in the current portion of the income tax provision reflected the impact of fluctuating, year-over-year net deferrals, largely associated with the earnings of the Petro-Canada Oil and Gas partnership. The higher exploration expense results from an expanded program in Western Canada, as well as write-offs of $39 million in connection with Algerian activities and $28 million for the evaluation of oil sands development opportunities. The increase in current income taxes was a major factor contributing to the 25 per cent decline in Upstream cash flow.

Total production in 2001 averaged 196 500 barrels of oil equivalent (BOE) per day, consisting of 77 400 barrels of oil and liquids and 714 million cubic feet of natural gas (converted at 6 000 cubic feet of gas to one barrel of oil equivalent). Production was seven per cent below the 212 200 BOE per day achieved in 2000, principally due to the sale of non-core properties. The average price received by Petro-Canada for our crude oil and natural gas liquids production was $37.30/bbl in 2001, down from $41.45 a year earlier. The average price received for natural gas was $6.00/mcf, up from $4.75 in 2000.

Total proved reserves climbed two per cent to 821 million BOE, as discoveries and extensions in Western Canada, the initial booking of reserves at MacKay River, the purchase of the En Naga property in Libya and additions from drilling at Terra Nova more than offset production and the sale of non-core properties. Independent petroleum reservoir engineering consultants are engaged annually to ensure Petro-Canada's hydrocarbon reserves estimates are appropriate. During 2001, Sproule Associates conducted a technical audit of Petro-Canada's reserves booking guidelines, processes, staff, review, approval and reporting procedures and determined that they met or exceeded industry standards. In addition, Arthur Andersen LLP, as contract auditor, tested the non-engineering management control processes used in establishing reserves.

OIL AND GAS PRODUCTION

Production was down slightly in 2001 due to asset sales.



■ Upstream production *(thousands of barrels of oil equivalent per day)*

– 1999 numbers have been restated to reflect a change in the gas-to-oil conversion factor, from 10:1 to 6:1.

Upstream Review & Outlook

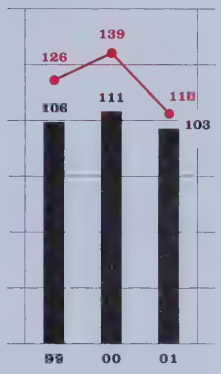
Overview

Petro-Canada's Upstream operations are focused in four core areas — East Coast offshore, oil sands, North American natural gas and international. Development of major oil discoveries offshore Newfoundland, exploitation of extensive oil sands potential in northern Alberta and international expansion spearhead the Company's growth plans. Crude oil prospects are complemented by an expanding portfolio of exploration opportunities for natural gas. Internationally, Petro-Canada positioned itself for long-term growth with the agreement to acquire the upstream oil and gas operations of Veba Oil & Gas GmbH in January 2002.

The primary risk for oil and gas producers is the ability to discover and produce reserves at an acceptable rate of return. To reduce risk, Petro-Canada maintains a balanced portfolio of exploration and development opportunities, mostly in proven or high potential areas. To optimize discovery in the mature Western Canada Sedimentary Basin, we pursue a strategy of concentric exploration, in and around areas of earlier discovery. To further mitigate exploratory risks, we employ and develop, in-house, high levels of technical expertise and leading-edge technology. To secure strategic and competitive advantages, Petro-Canada has entered into a variety of alliances with world-class suppliers of industry goods and services. These alliances provide preferential access, reliability, advanced technology, high quality and competitive prices, mitigating variability in costs associated with exploration and development as industry conditions fluctuate.

RESERVES REPLACEMENT

We again more than replaced production with new reserves.



- Natural gas *(per cent)*
- Total conventional oil and gas *(per cent)*

– Excludes acquisitions and divestitures

– Excludes Syncrude and MacKay River

– 1999 numbers have been restated to reflect a change in the gas-to-oil conversion factor, from 10:1 to 6:1.

East Coast Offshore

Offshore eastern Canada, Petro-Canada is a significant industry player with a stake in every major oil discovery and exploration area. In January 2002, we significantly expanded our crude oil production base on the Grand Banks, adding new production from our 34 per cent interest in the recently completed Petro-Canada operated Terra Nova development to our 20 per cent share of Hibernia. We expect our Grand Banks production to grow rapidly over the near term, as both Terra Nova and Hibernia climb to peak levels.

Production began at Terra Nova on January 20, 2002 with the first tanker loaded by January 31, 2002.

Terra Nova is the second major oil field to be brought on production on the Grand Banks but, in many respects, a "project of firsts" due to the numerous leading-edge engineering solutions required in its development. Noteworthy firsts include:

- the first floating production, storage and offloading vessel (FPSO) on the Grand Banks;
- the first FPSO designed to withstand the impact of a 100 000 tonne iceberg;
- the first fully-automatic quick-disconnectable turret and riser system on an FPSO; and
- the first application of open glory holes to protect subsea equipment from scouring icebergs.

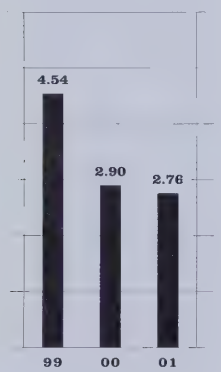
The 2001 work program included remedial work on the FPSO, offshore hook-up to the subsea risers and umbilicals and commissioning of both subsea and topsides facilities. Field activity included drilling and completing five wells — three oil producers and two water injectors — and installing flowlines to link the wells with the FPSO. Well testing confirmed expectations as to productivity, quality and structure of the reservoir. At start-up, five producing oil wells, two water injection wells and one gas injector were ready for operation. Drilling plans for 2002 include six development wells — two producers, three water injectors and one gas injector.

Because wells were pre-drilled, we expect production to climb rapidly, rising to sustainable peak production of 125 000 b/d (42 500 b/d net to Petro-Canada) by year-end 2002. We estimate our share of production in 2002 will average about 27 000 b/d. Reserves on the initially developed Graben and East Flank blocks are expected to have a production life of 12 to 14 years.

Late in 2001, Petro-Canada successfully drilled a delineation well into the adjacent Far East fault block. The well, Terra Nova C-69 1, encountered about 80 metres of Jeanne d'Arc reservoir sands, confirming the presence of hydrocarbons. The well was not flow tested, but data from well logs and sampling in the well bore suggest that the Far East sandstones are comparable to those of the reservoir sands in the developed portions of the Terra Nova field.

HIBERNIA OPERATING AND OVERHEAD COSTS

Operating and overhead costs per barrel continued to decline.



■ Unit operating and overhead costs
($ per barrel)

At Hibernia, strong operating performance in 2001 resulted in record production with Petro-Canada's share averaging 29 700 b/d, up from 28 900 b/d in the previous year, as two new gas injector wells alleviated earlier re-injection constraints. In 2002, Hibernia production is expected to average 150 000 b/d (30 000 b/d net to Petro-Canada), after allowing for the impact of a major maintenance shutdown planned for the latter part of the year. Project plans anticipate a sustained level of 160 000 b/d (32 000 b/d net to Petro-Canada) by the end of 2002.

At the close of 2001, 11 producing oil wells, five water injectors, and five gas injectors were in operation in the Hibernia formation. The Avalon formation had three wells capable of production with one water injector in operation. Drilling was in progress on an additional oil producer and another water injector. Hibernia's unit operating and overhead costs declined to $2.76/bbl in 2001 from $2.90/bbl in 2000.

Our East Coast growth strategy envisions expanding Petro-Canada's crude oil production base through field extensions at Hibernia and Terra Nova, and new stand-alone developments. Petro-Canada holds interests in the two remaining major undeveloped oil discoveries on the Grand Banks — White Rose (27.5 per cent) and Hebron/Ben Nevis (23.9 per cent). For the longer term, Petro-Canada holds exploratory interests totalling 4.8 million gross (1.6 million net) acres offshore Newfoundland.

Late in 2001, the Canada-Newfoundland Offshore Petroleum Board approved the Development Application filed by Petro-Canada and project operator Husky Oil Operations Ltd. for White Rose, subject to certain conditions. Petro-Canada and Husky expect to reach a decision on whether to proceed with development in the second quarter of 2002. Front-end engineering design is continuing and financing alternatives for securing an FPSO vessel are being evaluated. Hebron/Ben Nevis potential development work has been delayed, pending technology improvements to lower development costs.

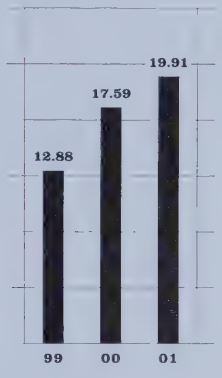
We are intensifying our search for new crude oil discoveries in the deeper waters of the continental slope. Extensive 3-D seismic data gathered over the past three years includes 4 600 square kilometres in the Flemish Pass and 1 200 square kilometres across the Salar Basin. In the Flemish Pass, we have defined prospects to be drilled when a deep-water drilling rig becomes available. In December 2001, we expanded our position in the Flemish Pass by acquiring a 33.4 per cent interest in a 544 000 acre parcel adjacent to our existing exploration licences. Interpretation of 3-D seismic from the Salar Basin is underway.

Oil Sands

Petro-Canada is a major participant in the development of Alberta's vast oil sands resources. Our 12 per cent share of Syncrude, the world's largest oil sands mining operation, is a core asset with a reserve life extending well beyond 35 years. Petro-Canada is also a leader in developing commercial *in situ* production of bitumen using steam-assisted gravity drainage (SAGD) technology. The continuing expansion of Syncrude and staged development of our *in situ* opportunities will provide major production growth for Petro-Canada over the next several years. The potential to link our expanding bitumen production with processing at our Edmonton refinery provides an opportunity to enhance financial returns.

SYNCRUDE OPERATING AND OVERHEAD COSTS

Operating and overhead costs increased due to operational problems and higher fuel costs.



■ Unit operating and overhead costs
($ per barrel)

Syncrude continued to be a major earnings contributor in 2001. The strong financial performance reflected a 10 per cent production gain and high oil prices for a large part of the year. Petro-Canada's share of Syncrude production in 2001 averaged 26 800 b/d, up from 24 300 b/d in 2000. The production gain would have been greater were it not for initial processing and reliability problems at the new Aurora mine, an extended shutdown of the hydrocracking unit and other ongoing reliability concerns. Syncrude took major steps to address these issues in 2001 and improved performance is expected in 2002, with our share of Syncrude production projected to rise to an average of 28 300 b/d. Unit operating and overhead costs in 2001 increased to $19.91/bbl, compared to $17.59/bbl in 2000, as the result of increased mining and extraction costs and higher fuel costs. Given the prospect of improved plant reliability and lower natural gas prices, we expect more acceptable unit costs in 2002.

During 2001, work commenced on the third stage of the Syncrude expansion, which includes upgrader expansion and the addition of a second production train at the Aurora mine. This stage is expected to increase production capacity by more than 100 000 b/d to a total of 370 000 b/d (44 000 b/d net to Petro-Canada) by 2005.

Petro-Canada sees major potential for profitable growth in its more than 300 000 net acres of oil sands leases considered prospective for *in situ* development. Staged development will allow us to apply learnings from each stage to future developments and assess evolving market conditions at each milestone. Bitumen can be recovered *in situ* where oil sands are too deep to be mined economically. Petro-Canada is applying steam-assisted gravity drainage technology, using pairs of horizontal wells, with steam injected into the reservoir through the top well to mobilize the bitumen, which drains into the lower production well. This technology can economically recover approximately 60 per cent of the oil in place. Petro-Canada is a leader in the development of SAGD, having been involved in the plants that piloted the technology.

Late in 2000 we began construction of our first commercial-scale bitumen production facility on our MacKay River acreage (owned 100 per cent by Petro-Canada). At year-end 2001, field development was well advanced with the initial 25 horizontal well pairs drilled and completed. Facility construction was over 60 per cent complete and the project remains on schedule and on budget. An insulated pipeline is under construction by Enbridge Pipelines (Athabasca) Inc. to transport bitumen from the production facilities to the Athabasca Pipeline Terminal, from where it will be transported to market. The pipeline is in the ground and construction of the pump station is two-thirds complete. We plan to begin steaming the reservoir in the third quarter of 2002, using gas-fired steam generation, with production start-up anticipated by year-end. Target production of 30 000 b/d should be achieved in mid-2003 and continue for 25 years. Operating technical risks associated with anticipated reservoir performance and recovery rates at MacKay River have been mitigated by the quality and duration of data available from a SAGD pilot project at an adjacent test facility. These factors, together with the results of extensive evaluation of core hole drilling and seismic data, have also reinforced our confidence in reserve estimates at MacKay River. Pre-production capital expenditures for the project are budgeted at $290 million.

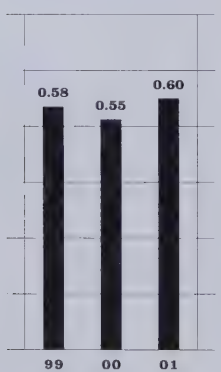
TransCanada Energy Limited has agreed to construct a 165 megawatt co-generation facility to provide electric power and additional steam to the MacKay River project. The power plant, expected to be operational by 2004, will be owned by TransCanada but operated as part of the MacKay River development. This facility will provide Petro-Canada with a long-term assured supply of low-cost power and steam, while reducing Alberta's greenhouse gas emissions and supplying power to the Alberta grid. Suncor Energy Marketing Inc. has committed to the long-term supply of up to 30 000 b/d of synthetic crude for blending with the MacKay River production to enable shipment on existing pipelines to North American markets.

Petro-Canada's next *in situ* development is planned at Meadow Creek, 45 kilometres south of Fort McMurray. Extensive seismic and delineation drilling on the property (owned 75 per cent by Petro-Canada) have confirmed significant bitumen production capability. Late in 2001, Petro-Canada filed a commercial application for the construction of an 80 000 b/d (60 000 b/d net to Petro-Canada) production facility at Meadow Creek. Following public consultation and regulatory approval, we will make a decision on proceeding based on economic evaluations and our experience at MacKay River. Construction could begin by late 2004, with initial production in 2007. Early estimates suggest the gross cost of the Meadow Creek development would be in the range of $700 million to $800 million.

Longer term, we may link our expanding bitumen production with processing at our Edmonton refinery, creating a fully integrated bitumen production and refining operation, with assured supply and the ability to build value at every step from wellhead to finished product. Integration would provide considerable insulation from heavy crude oil price fluctuations and eliminate bitumen over-supply risks. As a first step, Petro-Canada has filed an application to undertake a refinery conversion program that would enable the Edmonton refinery to replace its existing light crude oil feedstock with bitumen, while producing low-sulphur refined products. The first phase would convert sufficient capacity to allow upgrading and refining of about 85 000 b/d of bitumen. This phase would likely come on stream in 2007. A possible sequential second phase would add a further 85 000 b/d of bitumen capacity. Decisions to advance these plans will only be made following public consultation, regulatory approval and further economic evaluation. Preliminary cost estimates for the entire refinery conversion program are in the range of $4 billion to $5 billion, with capital spending spread over the next decade.

WESTERN CANADA OPERATING AND OVERHEAD COSTS

Costs per unit were up marginally due to higher industry costs.



■ Unit operating and overhead costs *($ per thousand cubic feet of gas equivalent)*

– Includes Western Canada gas, conventional oil and liquids

North American Natural Gas

Petro-Canada is one of the largest and most profitable producers of natural gas in Western Canada. For long-term growth in reserves and production, we have established strategic exploratory positions in the Mackenzie Delta region of the Northwest Territories, the Scotian Shelf and Alaska. These will provide us with significant opportunities to build on our track record as one of Canada's leading low-cost gas producers.

Western Canada

In Western Canada, natural gas production exceeded expectations, averaging 714 million cubic feet per day. This strong performance was achieved primarily through continued exploration and development successes in the Alberta Foothills and despite the sale, in 2000 and 2001, of non-core properties producing about 65 million cubic feet per day at the time of sale. Natural gas production in 2000 averaged 738 mmcf/d. In 2002, we expect volumes to again average in excess of 700 mmcf/d.

The average natural gas price realized by Petro-Canada was $6.00/mcf in 2001, up 26 per cent from $4.75/mcf in the previous year. Operating and overhead costs rose to $0.60 per thousand cubic feet of gas equivalent (mcfe) from $0.55/mcfe in 2000, due to increased electricity costs and the impact of a more competitive business environment on industry goods and services.

Conventional crude oil and natural gas liquids production declined to 18 600 b/d in 2001 from 23 400 b/d in 2000, as the result of property sales associated with Petro-Canada's planned exit from conventional oil production in Western Canada and natural field declines. In 2002, we expect our Western Canada conventional oil and natural gas liquids production to average in excess of 16 000 b/d.

During 2001, Petro-Canada raised its planned spending on conventional oil and gas in Western Canada by approximately $100 million to $475 million in response to additional opportunities we had identified for exploration and development, as well as general industry cost pressures arising from an increasingly competitive business environment. About 50 per cent of the $475 million program was allocated to the Alberta Foothills, mostly targeting new drilling opportunities. Solid gains in production reflect the program's success. In the Wildcat Hills area alone, production in December 2001 averaged 164 mmcf/d, up 18 per cent from 139 mmcf/d in the previous December.

In the Medicine Hat region of southeastern Alberta, Petro-Canada's annual shallow gas drilling program was again successful in adding natural gas production at a very competitive cost. An expanded program resulted in the successful drilling of 263 gross wells.

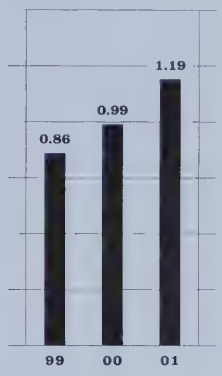
In northeastern British Columbia, drilling successes at Jedney and Clarke Lake, a plant expansion at Parkland and a new natural gas gathering facility at North Boundary combined to increase gas production in the area while adding 78 bcf of gas to reserves.

Petro-Canada drilled 367 successful wells in Western Canada in 2001 for a success rate of 93 percent. The program added 269 bcf of natural gas to proved reserves, enabling us to replace 103 per cent of 2001 production. Due to the net sale of producing properties, however, total proved gas reserves in Western Canada declined from 2 331 bcf to 2 228 bcf. Our three-year average finding and development cost for natural gas remained highly competitive at $1.19/mcfe.

In 2002, with capital expenditures for exploration and development in Western Canada budgeted at $425 million, we expect to replace production with new reserves. Plans include drilling about 45 exploration and development wells in the Alberta Foothills and 25 in northeastern British Columbia, as well as other drilling in west-central and southeastern Alberta.

NATURAL GAS FINDING AND DEVELOPMENT COSTS

Finding and development costs remained competitive despite rising service and supply costs.



■ Natural gas
($ per thousand cubic feet of gas equivalent)

– Three-year rolling average for proved reserves

– Excludes acquisitions and divestitures

Mackenzie Delta

Over the past two years, Petro-Canada has taken a leadership role in renewed exploration in the Mackenzie Delta region of the Northwest Territories. With interests in six blocks, covering approximately one million gross (0.6 million net) acres, Petro-Canada is one of the largest leaseholders in the Mackenzie Delta. Our exploration plans, which are being conducted jointly with Devon Energy Corporation, include multi-year, multi-well drilling activity. Early in 2001, we drilled a well on the Kurk block, the first exploration well in the Mackenzie Delta in more than a decade. Testing is currently underway. The 2001/02 winter program includes extensive seismic gathering and evaluation and the drilling of three wells, each about 3 000 metres in depth.

In the Mackenzie Delta, the six trillion cubic feet of natural gas discovered to date may be sufficient to justify the infrastructure required to bring production to southern markets. Substantial threshold reserves have already been found in Alaska. Industry groups are currently developing and evaluating competing proposals for pipelines to service the region, although a line is unlikely to be in place until late in this decade, at the earliest.

Offshore Nova Scotia

In the gas-prone Scotian Shelf off Nova Scotia, Petro-Canada increased its exploratory acreage to 1.5 million gross (0.8 million net) acres with the acquisition of a 50 per cent interest in a 366 000 acre parcel. We continue to evaluate the possibility of drilling our first well on the Scotian Shelf in 2002 or 2003.

Alaska

Petro-Canada again expanded its exploration focus beyond the Western Canada Sedimentary Basin in 2001 with the acquisition of exploratory acreage in Alaska. The purchase of a 100 per cent interest in 323 000 acres of exploration rights in the foothills area south of Prudhoe Bay gives us a strong foothold in this prospective region. Geology in the area is similar to the Alberta and British Columbia foothills where Petro-Canada has had considerable success in finding gas. The area is also close to a proposed natural gas pipeline route to southern markets.

International

In a subsequent event, Petro-Canada agreed to acquire the upstream oil and gas operations of Veba Oil & Gas GmbH, establishing International operations as a new core business.

On January 29, 2002, the Company agreed to acquire the upstream oil and gas operations of Veba Oil & Gas GmbH for a cash consideration of $3.2 billion, subject to closing adjustments and transaction costs. Veba's production and exploration interests are focused in three regions: the North Sea, North Africa and northern Latin America. Veba estimates its year-end 2001 proved oil and gas reserves at 585 million barrels of oil equivalent (BOE) and its 2002 production at about 174 000 BOE per day. *(These volumes are consistent with Veba's presentation methodology. In the future, Petro-Canada plans to report these acquired reserves and production on both a "before royalty" and "after royalty" basis consistent with Petro-Canada's reporting practices and Canadian and U.S. securities regulations.)* The Veba operations are a good strategic fit with Petro-Canada's existing assets and capabilities. Our knowledge and experience in the Canadian offshore will serve us well in the North Sea; our existing North Africa operations will complement Veba's Libyan assets; and our integrated oil sands expertise fits well with Veba's interest in the Cerro Negro integrated heavy oil development in Venezuela. Conclusion of the transaction is subject to a number of considerations, including host government approvals and rights of first refusal affecting assets in Norway, Egypt and Venezuela.

In an earlier strategic move, in 2001, we expanded our presence in North Africa through the purchase of an interest in the En Naga block in Libya's Sirte basin for $121 million. Our participation is governed by an Exploration and Production Sharing Agreement with the National Oil Corporation of Libya. The property contains two oil fields as well as exploration acreage. Development of the En Naga fields is in progress. As of year-end 2001, three of five planned production wells had been drilled, production facilities were nearing completion and construction was underway on a 96-kilometre, 12-inch pipeline that will transport En Naga production to a main transmission line. Initial gross production of 14 000 barrels per day (7 000 net to Petro-Canada) is expected by mid-2002.

In Algeria, Petro-Canada is participating in a production sharing contract with SONATRACH, the national oil company, in the Tinrhert block. Our 70 per cent share of production before royalty and the sharing of profit oil from the Tamadanet oil field averaged 2 300 b/d, down from 3 700 b/d in 2000 due to natural decline. An exploration well spudded in January 2002 will complete our drilling obligations under the second phase of the contract. During 2001, Petro-Canada elected to enter the final two-year phase, which includes a commitment to drill two additional wells by 2004.

In south-central Tunisia, we have exclusive rights to explore on the 1.8 million acre Tataouine block. Under an agreement with the Tunisian national oil company, ETAP, we have a commitment to drill two wells by 2005. A 1 000 kilometre 2-D seismic program completed in early 2001 is being evaluated.

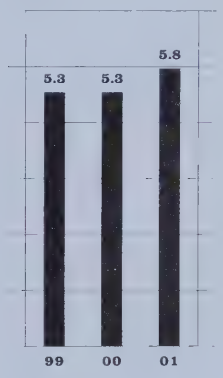
Downstream Sector

Downstream Financial Results

(millions of dollars, unless otherwise indicated)	**2001**	2000	1999
Earnings from operations	**300**	273	115
Gain (loss) on sale of assets	**1**	(1)	(9)
Net earnings	**301**	272	106
Cash flow	**589**	434	163
Operating return on capital employed (per cent)	**13.3**	13.0	5.7
Average capital employed	**2 251**	2 104	2 021

DOWNSTREAM OPERATING, MARKETING AND GENERAL COSTS

Per-litre costs increased in 2001 due to increased shutdown maintenance and lower sales volumes.



■ Unit operating, marketing and general costs *(cents per litre)*

2001 Compared with 2000

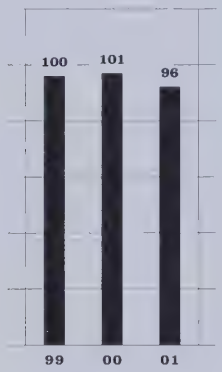
In 2001, a marked improvement in the performance of our Lubricants business, together with strong cracking margins and wide light/heavy oil price differentials, resulted in record earnings and return on capital in the Downstream. The contribution from Refining and Supply grew at a record rate through the first nine months of 2001 but diminished in the fourth quarter as the result of volume and margin declines due to the economic slowdown. As refinery profitability began to deteriorate during the latter part of the year, we undertook maintenance shutdowns at the Edmonton and Montreal refineries. In the previous year, planned shutdowns at Oakville and Montreal were deferred to capitalize on the then extremely favorable business environment. The volume of refined products sold declined marginally to 54 500 m^3/d from 55 400 m^3/d in 2000, as we reduced bulk refinery sales due to planned and unplanned shutdowns. The contribution to earnings from Sales and Marketing in 2001 was up significantly from the previous year, reflecting much stronger product margins. Downstream unit operating, marketing and general costs rose to 5.8 cents per litre, compared to 5.3 cents per litre in the previous year, as the result of increased shutdown maintenance costs and lower sales volume.

Downstream Review & Outlook

Petro-Canada enjoys outstanding brand recognition and a leading position in Canada's downstream industry. Our three refineries, in Edmonton, Oakville and Montreal, have a combined rated throughput capacity of 49 800 m^3/d, representing about 18 per cent of Canada's total refining capacity. We market Petro-Canada branded products through a nationwide network of retail and wholesale sites. Additionally, we have a world-scale lubricants plant in Mississauga that produces the highest quality hydro-treated products and low-cost white and high viscosity index oils.

REFINERY UTILIZATION

Refineries' utilization was impacted by planned maintenance shutdowns.



■ Crude capacity utilization *(per cent)*

– Our rated refinery crude capacity was increased in 2001, following process improvements. The 1999 figures are based on the lower rated capacity.

Refining and Supply

The goal of the Refining and Supply business is to achieve top quartile performance as measured by Solomon benchmarks. Our strategy is focused on earnings growth through improved operating controllables and disciplined capital management.

Strike action at a number of Petro-Canada's refineries and facilities during the year was resolved with ratification of new collective agreements that run until February 1, 2004. While the strike action was somewhat disruptive to our cost initiative program, the new agreement has provided a firm base for the drive towards a first quartile cost structure. Following the labour settlements and completion of the most recent refinery benchmarking study, new pacesetter teams were assembled to accelerate planning initiatives for 2002, focused on closing the performance gap with top quartile industry peers.

Increased shutdown activity, two power company outages affecting the Edmonton refinery and the slowdown in the economy combined to reduce refinery capacity utilization in 2001. Crude capacity utilization declined to 96 per cent, compared to 101 per cent in 2000.

The Oakville and Montreal refineries have significant capability to process heavy oil. In 2001, asphalt sales produced from these heavy crudes totalled 1.5 billion litres, close to a record level, despite a slowing economy. The financial benefit was enhanced by strong margins resulting from wide light/heavy crude oil price differentials.

In 2001, Petro-Canada planned modifications for our three refineries to meet regulatory requirements to reduce sulphur in gasoline. These modifications will enable Petro-Canada to achieve a 150 parts per million (ppm) gasoline pool average over the July 1, 2002 to December 31, 2004 time frame, as required by the federal government. Technology selection for the required further reduction to 30 ppm gasoline pool average by January 1, 2005 has been made for our Edmonton and Montreal refineries. We expect new desulphurization units at these refineries to be operating well in advance of government timelines. Technology selection for sulphur reduction to 30 ppm at the Oakville refinery is underway and required modifications are expected to be operational by the end of 2004.

Sales and Marketing

With an accelerated program, 44 per cent of Petro-Canada's 873 company-controlled retail sites had been converted to our new-image design at year-end 2001.

During 2001, Petro-Canada continued to build on its leading position as "Canada's Gas Station." Our retail network consists of 1 566 sites, of which 873 are company controlled. Average throughput per retail site in 2001 increased to 3.8 million litres, up from 3.7 million litres in 2000, mainly due to the success of our site re-imaging program. With annual throughputs averaging in excess of seven million litres, Petro-Canada's new-design sites are demonstrating a distinct market advantage. We accelerated the re-imaging program in 2001, converting an additional 63 sites. In 2002, an additional 60 sites will be converted. Our plan is to complete the re-imaging of all company-controlled sites by the end of 2005 with the near-term emphasis on major urban markets.

In 2001, Petro-Canada's sales of non-petroleum products and services increased by 15 per cent, mainly through integrated convenience stores and car washes, reflecting the success of the retail site redevelopment program. Our retail strategy will continue to focus on improving the convenience of Petro-Canada's products and services.

In the highly competitive environment of retail marketing, where customer loyalty is the linchpin for success, our achievements are reflected in growing membership in Petro-Points, Petro-Canada's branded customer loyalty program. At year-end 2001, about 5.5 million (or four out of ten) Canadian households were Petro-Points members. In August 2001, to make our loyalty program even more compelling to consumers, we launched a points exchange program with Sears Canada. This new arrangement, whereby points can be combined and redeemed for either Petro-Points or Sears Club rewards, enables members to obtain a broader range of rewards more quickly.

In the wholesale channel, our industrial operations continued to focus on the commercial road transport market. Petro-Canada's Petro-Pass wholesale network, with 205 sites, is the nation's largest. Services include 24 hours per day, 365 days a year access to fueling centres, high speed pumps for faster fueling, and North American fueling capability through a U.S. truck stop partnership. While maintaining our best-in-class status in the wholesale channel, we continue to upgrade and expand our products and services to best meet the needs of the trucking industry.

Lubricants

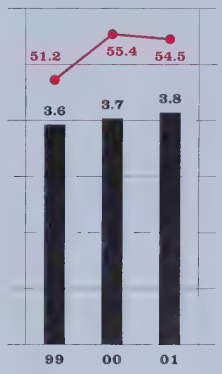
The Lubricants business made a significant contribution to earnings in 2001, while continuing to improve the mix of premium sales.

Petro-Canada's Lubricants plant is the largest producer of lubricant base stocks in Canada and one of the largest producers of pharmaceutical and food-grade white oils in the world. Manufacturing capabilities include premium quality lubricants for high-end industrial applications and next-generation engine oils. Recent trends in products for the automotive industry have placed more stringent requirements on the base oil component. Improved base oil high-temperature properties are key to meeting the requirements of the finished automotive product. Base oils with these improved characteristics command a premium over conventional base oils. Petro-Canada is well-positioned to capitalize on the growing market need for higher quality base oils.

Wider margins for base lubricants and success in improving high-margin sales volumes combined to generate a strong financial performance for Lubricants in 2001. Total lubricants sold declined to 744 million litres, from 763 million litres in 2000, due to selective withdrawal from some low-margin business. High-margin volumes, including sales of new automotive engine oils and fluids, rose 15 per cent to account for over 55 per cent of total volumes. Our goal is to grow these "value-added" sales until they account for at least 75 per cent of the sales mix. Cost reduction, improvements in energy efficiency and plant reliability are also part of our long-term growth and profitability plans.

PRODUCT SALES

Total Downstream sales decreased by 2 per cent in 2001; however sales per retail site continued to grow.



■ Retail throughput per site *(millions of litres per year)*

● Petroleum product sales *(thousands of cubic metres per day)*

Shared Services

Shared Services Financial Results

(millions of dollars)	**2001**	2000	1999
Net expenses[1]	**(89)**	(117)	(122)
Cash flow[1]	**(53)**	(67)	(84)

1 Before reorganization costs in 2000.

2001 Compared with 2000

Shared Services is structured as a cost centre that includes interest expense, general corporate revenues and expenditures, and investment income. The net expense decline in 2001 mainly reflects increased investment income partially offset by higher foreign exchange losses and lower income tax recoveries.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Cash Flows

(millions of dollars)	2001	2000	1999
Net cash inflows (outflows) before change in operating working capital:			
Cash flow	**1 688**	1 870	964
Investing activities	**(1 564)**	(489)	(945)
Financing activities	**(909)**	(214)	(89)
	(785)	1 167	(70)
Decrease (increase) in operating working capital and other	**151**	42	(155)
(Decrease) increase in cash and short-term investments	**(634)**	1 209	(225)

Operating Activities

The 10 per cent decline in cash flow to $1 688 million in 2001 was mainly the result of an approximate $300 million reduction in net deferrals of current income taxes, compared with the previous year. In the Upstream, net deferrals in 2001, mainly related to earnings in the Petro-Canada Oil and Gas partnership, increased current taxes by about $100 million. This compares to a reduction in current income taxes from net deferrals of about $350 million in the previous year. In the Downstream, the inventory accounting method used for income tax purposes resulted in a $98 million reduction in current taxes in 2001, compared with a $53 million increase in 2000.

The decrease of $151 million in operating working capital was mainly due to a drop in accounts receivable partially offset by a drop in accounts payable and accrued liabilities. The lower levels of accounts receivable and payable reflect the decline in prices for crude oil and natural gas over the past year. The drop in cash and short-term investments is primarily comprised of the repayment of $471 million (U.S.$300 million) of long-term debt and the repurchase of common shares for a total cost of $362 million in 2001.

Investing Activities

Capital and Exploration Expenditures

(millions of dollars)	2001	2000	1999
Upstream[1]			
Western Canada oil and gas exploration and development	**467**	371	276
Hibernia and Terra Nova	**235**	282	283
Other East Coast Offshore	**44**	75	42
Syncrude, MacKay River and other oil sands	**304**	110	107
Mackenzie Delta and Alaska	**72**	34	—
International	**32**	43	47
Property acquisitions	**121**	1	22
Other	**9**	11	16
	1 284	927	793
Downstream			
Refining and supply	**206**	102	110
Marketing	**156**	143	90
Lubricants	**21**	19	20
	383	264	220
Shared Services	**14**	12	8
Total property, plant and equipment and exploration	**1 681**	1 203	1 021
Deferred charges and other assets	**10**	8	5
Total	**1 691**	1 211	1 026

1 Includes exploration expenses charged to earnings of $245 million in 2001, $171 million in 2000 and $78 million in 1999.

2001 Compared with 2000

The 39 per cent increase in Upstream capital expenditures on property, plant and equipment and exploration expense reflected: further major investments for exploration and development of natural gas in Western Canada; $186 million on development of Terra Nova; $69 million for natural gas exploration in the Mackenzie Delta; $121 million for the acquisition of undeveloped reserves and exploratory acreage in Libya; $99 million for Syncrude, including commencement of the Stage 3 expansion; $142 million towards development of the MacKay River oil sands *in situ* project; and $62 million for other Oil Sands work, including positioning for a second *in situ* development. Downstream capital expenditures increased as we accelerated the development of our new-image retail sites and commenced investments to comply with sulphur-in-gasoline regulations.

During 2001, Petro-Canada sold a small number of non-core assets for proceeds of $127 million, essentially completing the asset divestiture program initiated in 2000.

2002 Capital Budget

Petro-Canada's capital expenditure budget for 2002 amounts to $1 845 million (excluding requirements for the Veba assets to be acquired), up 10 per cent from expenditures of $1 681 million in 2001, reflecting our confidence in the opportunities available to us. About $1 345 million of 2002 budgeted expenditures are allocated to Upstream activities, $480 million to the Downstream, and $20 million for corporate and other purposes.

Petro-Canada will continue to allocate substantial funding to our natural gas program in Western Canada and the Mackenzie Delta. The capital budget will also continue to advance oil sands development. Planned investments include about $220 million for the Company's share of capital improvements and Stage 3 Expansion expenditures at Syncrude, an estimated $128 million to complete the MacKay River development, $140 million to fund preparatory work for the proposed bitumen feed conversion at the Edmonton refinery and approximately $40 million for development of Meadow Creek and other Oil Sands work. About $220 million has been provided to fund further development of East Coast offshore oil production, including ongoing drilling at Hibernia and Terra Nova and, if sanctioned by the project participants, development of White Rose.

In the Downstream, budgeted expenditures focus on positioning Petro-Canada for a profitable future while lessening the environmental impact of our operations and products. The majority of refining investments will be to achieve compliance with the new sulphur-in-gasoline regulations. Marketing expenditures will provide for the continued roll-out of Petro-Canada's successful new-image retail sites program.

Financing Activities

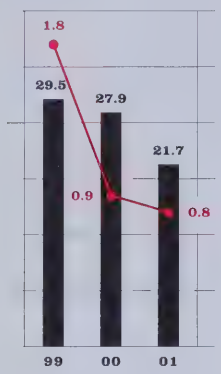
Sources of Capital Employed

(millions of dollars)	**2001**	2000	1999
Long-term debt, including current portion	**1 401**	1 774	1 711
Shareholders' equity	**5 061**	4 591	4 083
	6 462	6 365	5 794
Foreign currency translation adjustment on long-term debt[1]	**(187)**	(130)	(87)
Total	**6 275**	6 235	5 707

1 The translation adjustment on long-term debt is amortized over the remaining term of the debt. The weighted average term of the debt was 23 years at December 31, 2001. Effective January 1, 2002, Petro-Canada adopted the recommendation of the CICA that foreign currency exchange gains and losses on long-term debt should be recognized immediately in the income statement and cease to be deferred. The foreign currency translation adjustment as at December 31, 2001 of $187 million ($184 million after tax) will be charged to retained earnings and prior years will be restated.

KEY DEBT RATIOS

Balance sheet strength is reflected in conservative debt ratios.

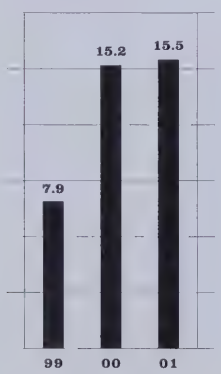


■ Debt to debt plus equity *(per cent)*

● Debt to cash flow *(times)*

INTEREST COVERAGE

A positive interest coverage ratio demonstrates more than sufficient earnings to cover interest charges on debt.



■ Interest coverage ratio *(times)*

– Calculated on an EBITDAX basis

The $373 million reduction in long-term debt in 2001 reflects the repayment of $471 million (U.S.$300 million) of 8.6% unsecured notes, with a partial offset from the effects of the weaker Canadian dollar exchange rate on U.S. dollar denominated debt.

Petro-Canada has agreed to acquire the upstream oil and gas operations of Veba Oil and Gas GmbH for a cash consideration of the current equivalent of $3.2 billion, subject to closing adjustments and transaction costs. The assets will be acquired in an all-cash transaction, financed by committed credit facilities, underwritten by the Royal Bank of Canada and Deutsche Bank AG, Canada Branch. These committed facilities will ultimately be syndicated to include other major financial institutions. The transaction is expected to close in stages during 2002. The additional debt taken on to finance the acquisition will significantly increase our financial leverage but we expect debt to cash flow, our key leverage measure, to remain close to our target of two times. At December 31, 2001, as a result of Petro-Canada's strong financial performance, this ratio stood at 0.8 times. Debt to debt plus equity, which stood at 21.7 per cent at 2001 year-end, also will increase but we expect to reduce this, over time, to our target level of 30 per cent. While the primary purpose of the new credit facilities is to fund the acquisition, a certain portion can also be used for general corporate purposes. Therefore, for operating purposes as at January 31, 2002, Petro-Canada has access to this portion of the new bank facilities, additional bank committed lines of credit and a commercial paper program totalling $1 825 million. Petro-Canada will continue to use its cash position, and the issuance of short-term debt if necessary, to meet working capital and bridge financing requirements. As of December 31, 2001, Petro-Canada had cash and short-term investments of $781 million and no commercial paper outstanding.

Petro-Canada's Normal Course Issuer Bid, initiated effective November 1, 2000, expired on October 31, 2001. During 2001, in excess of nine million shares were repurchased at a cost of $362 million.

In June 2001, the Government of Canada passed legislation eliminating the 25 per cent restriction on foreign ownership of Petro-Canada's stock and increasing the limit on individual ownership from 10 per cent to 20 per cent. These changes resulted in the conversion of Petro-Canada's variable voting shares into common shares on a one-for-one basis, and the deletion of the variable voting shares class entirely. These new ownership rules provide Petro-Canada with improved competitive access to international capital markets.

Petro-Canada reviews its dividend strategy from time to time to ensure the alignment of dividend policy with shareholder expectations and our financial and growth objectives. In 2001, Petro-Canada paid $106 million in dividends, compared with $109 million in 2000. The current quarterly dividend is $0.10 per share.

Financial Ratios

	2001	2000	1999
Current ratio	**1.4**	1.4	1.2
Interest coverage (times)			
— earnings basis	**10.1**	10.3	3.7
— EBITDAX basis	**15.5**	15.2	7.9
— cash flow basis	**15.6**	15.2	8.2
Debt to cash flow (times)	**0.8**	0.9	1.8
Debt to debt plus equity (per cent)	**21.7**	27.9	29.5

RISK MANAGEMENT

Petro-Canada's risk management activities are conducted according to policies and guidelines established by the Board of Directors, using hedging, insurance and other techniques.

Our risk management policy prohibits the use of derivative instruments for speculative purposes. Petro-Canada uses derivatives primarily to hedge physical transactions for operational needs and to facilitate sales to customers. Commodity prices and margins may be hedged occasionally to capture opportunities that represent extraordinary value. Except as specifically authorized by the Board, the term of hedging instruments cannot exceed 18 months. We transact derivatives with counterparties who possess a minimum long-term credit rating of A (unless otherwise approved by the Board) under a signed International Swap Dealers Association agreement. Credit limits take into account current and potential exposure to losses due to non-performance of a counterparty and reduce credit risk concentration with any single counterparty. Monitoring and reporting of the derivatives portfolio includes periodic testing of the fair value of all outstanding derivatives. The net effect of commodity and currency hedging during 2001 increased earnings by about $10 million after tax. No interest rate hedges were implemented.

As at December 31, 2001, crude oil, natural gas and foreign exchange contracts had been bought forward to mitigate exposure on fixed-price natural gas and refined product sales. Short-term hedge positions were also in place for refining supply and product purchases. The average level of derivative instruments outstanding during 2001 did not differ materially from the position as at December 31, 2001.

Petro-Canada has future commitments to sell and transport natural gas associated with normal operations. About four per cent of our estimated 2002 natural gas production is sold under future fixed-price commitments at an average plant gate netback price of $2.78 per mcf.

Petro-Canada manages operational risk through comprehensive risk assessment and loss management processes, and maintains adequate insurance coverage. We place insurance coverage globally, with financially secure insurers. Limits of insurance are based on engineering risk assessments and deductibles are set at levels that reflect our ability to retain the risk.

CORPORATE RESPONSIBILITY

While Petro-Canada is in business to provide a competitive return to our shareholders, we recognize that economic performance is not the only criterion on which our company is evaluated, nor does it provide a complete picture of what we do.

At Petro-Canada, we understand the interdependence between financial performance, environmental performance and commitment to the community.

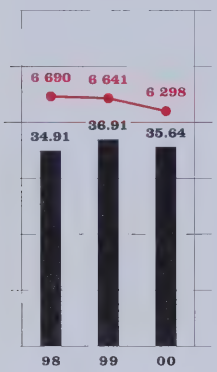
To review our performance in environmental stewardship, health and safety and community involvement in more detail than can be accommodated in the Annual Report, we published our first annual Report to the Community in 2001. The report gathers data on key non-financial performance measures, enabling the public to assess our ongoing efforts in these areas. The Report to the Community can be viewed on our Web site at www.petro-canada.ca, or obtained from Corporate Communications. The 2001 Report to the Community will be available in July 2002.

Environment, Health and Safety

Petro-Canada has evolved its management and internal reporting systems to provide a very high level of assurance that corporate responsibility is part of our day-to-day business decision-making. These governance systems begin with the Board of Directors and extend throughout the company.

GREENHOUSE GAS EMISSIONS VERSUS PRODUCTION

Petro-Canada is committed to reducing greenhouse gas emissions in our upstream and downstream operations, primarily by improving energy efficiency.



■ Total Upstream and Downstream production *(million cubic metres of oil equivalent/year)*

● GHG emissions *(kilotonnes/year)*

– 2001 data is not yet available; data is based on reporting 100% from Petro-Canada operated properties.

Petro-Canada executives are responsible for developing operational procedures and standards in compliance with our environment, health and safety policies and Total Loss Management (TLM) standards under which we conduct a major review of each business unit every four years. Our Executive Leadership Team reviews environment, health and safety performance monthly, and the Environment, Health and Safety committee of the Board of Directors is briefed three times a year.

In 2001, we invested $135 million in environmental programs, including $79 million for operating expenses and $56 million in capital expenditures for facility upgrades. We expect environmental costs to remain high, as we prepare to meet new federal limits for sulphur in gasoline, future fuel reformulation requirements, and tighter environmental standards for oil and gas production.

Petro-Canada recognizes and shares the public concern about global climate change. We are responding to this concern with continued investment to reduce direct emissions and to improve the energy efficiency of our operations. Since 1990, Petro-Canada has eliminated over 1.3 million tonnes of annual ongoing greenhouse gas (GHG) emissions. In 2000, total GHG emission levels were 8.8 per cent below 1990 levels, at 6.298 million tonnes (CO_2 equivalent), despite a 34 per cent growth in overall production. Emissions in 2000 were five per cent lower than in 1999. Data for 2001 will be provided in this year's Report to the Community.

The safety and well-being of our employees is a high priority for Petro-Canada. Occupational health and safety programs are designed to contribute to employee well-being and provide a safe and healthy work environment. In 2001, some safety initiatives were interrupted due to strikes. Petro-Canada also experienced a new and challenging work environment on the Terra Nova vessel during commissioning and start-up. While we have seen a continual decline in injuries and success in many of our facilities, our overall Employee Recordable Injury Frequency (per 200 000 person-hours) rose to 1.14 from 0.94 in 2000. Recordable injuries rose to 46 from 40 in 2000. We will introduce behavior-based safety programs in all refineries during 2002, and the pace of activity at Terra Nova has now stabilized with the start of production. In addition, an overall Fitness to Work initiative that focuses on employee health and the work environment is in progress throughout Petro-Canada.

Community Involvement

Petro-Canada's success depends on the support of Canadians, so we actively invest and participate in the communities where we work and live across the country.

In 2001, Petro-Canada invested $6.1 million in 206 Canadian non-profit organizations in four focus sectors — education, the environment, health and community services, and arts and culture. The company is also a major supporter of amateur sport through our partnership with the Canadian Olympic Association. Petro-Canada supports the Olympic Torch Scholarship Fund, Coaching Awards, Athletes Podium Fund and the Canadian Paralympics. Through our Volunteer Energy Program, we provided 338 grants of $500 each to charities supported by employees and retirees who give their time to the community.

World Business Council for Sustainable Development

Imagine A Caring Company

® Official Mark of the Canadian Olympic Association

VCR-MVP inc. Gold™ Champion Level Reporter

MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

The preparation and presentation of the Company's consolidated financial statements is the responsibility of management. The financial statements have been prepared in accordance with generally accepted accounting principles and necessarily include estimates which are based on management's best judgments. Information contained elsewhere in the Annual Report is consistent, where applicable, with that contained in the financial statements.

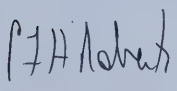
Management is also responsible for installing and maintaining a system of internal controls to provide reasonable assurance that assets are safeguarded and that reliable financial information is produced for preparation of financial statements.

Arthur Andersen LLP, a firm of chartered accountants, were appointed by the shareholders as external auditors to conduct an independent examination and express their opinion on the consolidated financial statements. The Auditors' Report outlines the auditors' opinion and the scope of their examination. The Company also contracted Arthur Andersen LLP to provide other audit services in 2001, including a review of the system of internal controls to ensure that there are no significant weaknesses.

The Board of Directors is responsible for overseeing management's performance of its responsibilities for financial reporting and internal control. The Board exercises this responsibility with the assistance of the Audit, Finance and Risk Committee of the Board.



Ronald A. Brenneman
Chief Executive Officer



Ernest F.H. Roberts
Senior Vice-President and Chief Financial Officer

January 31, 2002

AUDIT, FINANCE AND RISK COMMITTEE OF THE BOARD OF DIRECTORS

The Board of Directors exercises its responsibility for overseeing management's performance of its financial reporting and internal control responsibilities with the assistance of the Audit, Finance and Risk Committee of the Board.

The Committee, which is composed of not less than three (currently five) directors who are not employees of the Company, reviews the annual consolidated financial statements prior to their approval by the Board. The Committee also reviews financial information contained in prospectuses and in reports filed with regulatory authorities, as required, as well as quarterly financial information.

With respect to the external auditors, the Committee reviews the terms of engagement, the annual audit plan, the Auditors' Report and the results of the audit. The Committee discusses the auditors' independence from management and the Company with the external auditors who provide written confirmation of their independence within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta, the Securities Acts administered by the Securities and Exchange Commission and the requirements of the Independence Standards Board in the United States. The Committee also recommends to the Board a firm of external auditors to be appointed by the shareholders.

With respect to Arthur Andersen LLP's engagement as contract auditor for 2001 to review the system of internal controls, the Committee received periodic reports, reviewed significant findings and recommendations and approved their engagement contract and review plan.

The Committee also reviews and makes recommendations to the Board regarding practices in place for managing risk, insurance coverage and other matters which could materially affect the Company's financial or corporate structure.

Senior management, the external auditor and the contract auditor attend all Audit, Finance and Risk Committee meetings and each is provided with the opportunity to meet privately with the Committee.



Claude Fontaine
Chairman of the Audit, Finance and Risk Committee

January 31, 2002

AUDITORS' REPORT

To the Shareholders of Petro-Canada:

We have audited the consolidated balance sheet of Petro-Canada as at December 31, 2001 and 2000 and the consolidated statements of earnings, retained earnings and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2001 and 2000 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001 in accordance with Canadian generally accepted accounting principles.



Arthur Andersen LLP
Chartered Accountants
Calgary, Alberta

January 31, 2002

CONSOLIDATED STATEMENT OF EARNINGS

(stated in millions of Canadian dollars)

For the years ended December 31,	2001	2000	1999
REVENUE			
Operating	**$ 8 582**	$ 9 372	$ 6 095
Investment and other income (Note 5)	**108**	149	52
	8 690	9 521	6 147
EXPENSES			
Crude oil and product purchases	**4 687**	5 537	3 436
Operating, marketing and general (Note 6)	**1 670**	1 619	1 512
Exploration	**245**	171	78
Depreciation, depletion and amortization	**568**	584	558
Interest	**135**	144	141
	7 305	8 055	5 725
EARNINGS BEFORE INCOME TAXES	**1 385**	1 466	422
PROVISION FOR INCOME TAXES (Note 7)			
Current	**528**	363	147
Future	**(47)**	210	42
	481	573	189
NET EARNINGS	**$ 904**	$ 893	$ 233
EARNINGS PER SHARE (dollars) (Notes 3 and 8)			
Basic	**$ 3.41**	$ 3.28	$ 0.86
Diluted	**$ 3.38**	$ 3.25	$ 0.85

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

(stated in millions of Canadian dollars)

For the years ended December 31,	2001	2000	1999
RETAINED EARNINGS AT BEGINNING OF YEAR, as previously reported	**$ 897**	$ 288	$ 147
Adjustment for the cumulative effect of change in accounting policy on prior periods (Note 3)	**—**	(175)	—
RETAINED EARNINGS AT BEGINNING OF YEAR, as restated	**897**	113	147
Net earnings	**904**	893	233
Dividends on common shares	**(106)**	(109)	(92)
RETAINED EARNINGS AT END OF YEAR	**$ 1 695**	$ 897	$ 288

CONSOLIDATED STATEMENT OF CASH FLOWS

(stated in millions of Canadian dollars)

For the years ended December 31,	2001	2000	1999
OPERATING ACTIVITIES			
Net earnings	**$ 904**	$ 893	$ 233
Items not affecting cash flow (Note 9)	**539**	806	653
Exploration expenses (Note 13)	**245**	171	78
Cash flow	**1 688**	1 870	964
Decrease (increase) in operating working capital related to operating activities and other (Note 10)	**55**	87	(148)
Cash flow from operating activities	**1 743**	1 957	816
INVESTING ACTIVITIES			
Expenditures on property, plant and equipment and exploration (Note 13)	**(1 681)**	(1 203)	(1 021)
Proceeds from sales of assets (Note 5)	**127**	722	81
Increase in deferred charges and other assets, net	**(10)**	(8)	(5)
Decrease (increase) in operating working capital related to investing activities (Note 10)	**96**	(44)	(13)
	(1 468)	(533)	(958)
FINANCING ACTIVITIES			
Reduction of long-term debt	**(475)**	(4)	(3)
Purchase of common shares (Note 17)	**(362)**	(134)	—
Dividends on common shares	**(106)**	(109)	(92)
Proceeds from issue of common shares	**34**	33	6
(Increase) decrease in operating working capital related to financing activities (Note 10)	**—**	(1)	6
	(909)	(215)	(83)
(DECREASE) INCREASE IN CASH AND SHORT-TERM INVESTMENTS	**(634)**	1 209	(225)
CASH AND SHORT-TERM INVESTMENTS AT BEGINNING OF YEAR	**1 415**	206	431
CASH AND SHORT-TERM INVESTMENTS AT END OF YEAR	**$ 781**	$ 1 415	$ 206

CONSOLIDATED BALANCE SHEET

(stated in millions of Canadian dollars)

As at December 31,	2001	2000
ASSETS		
CURRENT ASSETS		
Cash and short-term investments (Note 11)	**$ 781**	$ 1 415
Accounts receivable	**758**	1 289
Inventories (Note 12)	**455**	455
Prepaid expenses	**15**	20
	2 009	3 179
PROPERTY, PLANT AND EQUIPMENT, NET (Note 13)	**7 460**	6 660
DEFERRED CHARGES AND OTHER ASSETS (Note 14)	**352**	291
	$ 9 821	$ 10 130
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	**$ 1 158**	$ 1 561
Income taxes payable	**234**	194
Current portion of long-term debt	**5**	454
	1 397	2 209
LONG-TERM DEBT (Note 15)	**1 396**	1 320
DEFERRED CREDITS AND OTHER LIABILITIES (Note 16)	**481**	477
FUTURE INCOME TAXES (Notes 3 and 7)	**1 486**	1 533
COMMITMENTS AND CONTINGENT LIABILITIES (Note 22)		
SHAREHOLDERS' EQUITY (Notes 3 and 17)	**5 061**	4 591
	$ 9 821	$ 10 130

Approved on behalf of the Board



Ronald A. Brenneman
Director



Claude Fontaine
Director

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(tabular amounts stated in millions of Canadian dollars)

Note 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of Presentation The consolidated financial statements include the accounts of Petro-Canada and of all subsidiary companies ("the Company") and comply with Canadian generally accepted accounting principles.

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingencies at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

(b) Cash and Short-Term Investments Cash and short-term investments comprise cash in the bank, less outstanding cheques, and deposits with a maturity of less than one year.

(c) Inventories Inventories are stated at the lower of cost and net realizable value. Cost of crude oil and products is determined primarily on a "last-in, first-out" basis.

(d) Investments Investments in companies over which the Company has significant influence are accounted for on the equity method. Other long-term investments are accounted for on the cost method.

(e) Property, Plant and Equipment Investments in exploration and development activities are accounted for on the successful efforts method. Under this method the acquisition cost of unproved acreage is capitalized. Costs of exploratory wells are initially capitalized pending determination of proved reserves and costs of wells which are assigned proved reserves remain capitalized while costs of unsuccessful wells are charged to earnings. All other exploration costs are charged to earnings as incurred. Development costs, including the cost of all wells, are capitalized.

Substantially all of the Company's exploration and development activities are conducted jointly with others. Only the Company's proportionate interest in such activities is reflected in the financial statements.

The interest cost of debt attributable to the construction of major new facilities is capitalized during the construction period.

(f) Depreciation, Depletion and Amortization Depreciation and depletion of capitalized costs of oil and gas producing properties are calculated using the unit of production method.

Depreciation of other plant and equipment is provided on either the unit of production method or the straight line method, based on the estimated service lives of the related assets, as appropriate.

The carrying amounts of unproved properties are evaluated for impairment with any such impairment being charged to earnings.

(g) Future Removal and Site Restoration Costs Estimated future removal and site restoration costs which are probable and can be reasonably determined are provided for on either the unit of production method or the straight line method, based on the estimated service lives of the related assets, as appropriate. Future removal and site restoration costs for inactive downstream sites, net of expected recoveries, are provided for at the time a decision is made to decommission the site.

(h) Translation of Foreign Currency Monetary assets and liabilities are translated into Canadian dollars at rates of exchange in effect at the balance sheet date. Other assets and related depreciation, depletion and amortization, other liabilities, revenue and other expense items are translated at rates of exchange in effect at the respective transaction dates. The resulting exchange gains or losses are included in earnings, except for unrealized exchange gains or losses arising on translation of long-term debt, which are deferred and amortized over the remaining term of the debt.

Foreign operations are integrated with the Company's other activities and are translated in the manner described above.

(i) Hedging Activity The Company may use derivative instruments to reduce its exposure to foreign exchange, interest rate and commodity price fluctuations. Gains and losses on these contracts, all of which constitute effective hedges, are deferred and recognized as a component of the related transaction.

(j) Stock Option Plan The Company maintains a stock option plan for directors, officers and certain employees. Consideration paid on exercise of stock options is credited to common shares and no compensation expense is recognized when stock options or stock are issued.

Note 2 SEGMENTED INFORMATION

The Company operates in two business segments:

Upstream, comprising: exploration, development, production, transportation and marketing activities for crude oil, natural gas and natural gas liquids; and oil sands.

Downstream, comprising: purchase and sale of crude oil; refining crude oil into oil products; and distribution and marketing of these and other purchased products.

	Upstream			Downstream		
	2001	2000	1999	**2001**	2000	1999
Revenue						
Sales to customers and other revenues	**$ 1 510**	$ 1 718	$ 1 174	**$ 7 158**	$ 7 782	$ 4 975
Inter-segment sales	**642**	619	516	**6**	6	14
Segment Revenue	**2 152**	2 337	1 690	**7 164**	7 788	4 989
Expenses						
Crude oil and product purchases	**—**	92	291	**4 687**	5 446	3 144
Inter-segment transactions	**6**	6	14	**642**	619	516
Operating, marketing and general	**466**	420	455	**1 165**	1 079	994
Exploration	**245**	171	78	**—**	—	—
Depreciation, depletion and amortization	**374**	384	399	**193**	187	158
Interest	**—**	—	—	**—**	—	—
	1 091	1 073	1 237	**6 687**	7 331	4 812
Earnings before income taxes	**1 061**	1 264	453	**477**	457	177
Provision for income taxes	**369**	488	204	**176**	185	71
Reorganization costs (Note 6)	**—**	—	—	**—**	—	—
Net Earnings	**$ 692**	$ 776	$ 249	**$ 301**	$ 272	$ 106
Capital and Exploration Expenditures						
Property, plant and equipment and exploration expenditures	**$ 1 284**	$ 927	$ 793	**$ 383**	$ 264	$ 220
Deferred charges and other assets	**(6)**	4	(3)	**16**	7	(5)
	$ 1 278	$ 931	$ 790	**$ 399**	$ 271	$ 215
Cash Flow	**$ 1 152**	$ 1 538	$ 885	**$ 589**	$ 434	$ 163
Total Assets	**$ 5 304**	$ 4 959	$ 5 052	**$ 3 556**	$ 3 609	$ 3 301
Capital Employed	**$ 3 438**	$ 2 920	$ 3 525	**$ 2 337**	$ 2 165	$ 2 084

Financial information by business segment is presented in the following table as though each segment were a separate business entity. Inter-segment transfers of products, which are accounted for at market value, are eliminated on consolidation. Shared Services includes investment income, interest expense and general corporate revenue and expense. Shared Services assets are principally cash and short-term investments and other general corporate assets.

Shared Services			Consolidated		
2001	2000	1999	**2001**	2000	1999
$ 22	$ 21	$ (2)	**$ 8 690**	$ 9 521	$ 6 147
—	—	—			
22	21	(2)			
—	(1)	1	**4 687**	5 537	3 436
—	—	—			
39	54	63	**1 670**	1 553	1 512
—	—	—	**245**	171	78
1	13	1	**568**	584	558
135	144	141	**135**	144	141
175	210	206	**7 305**	7 989	5 725
(153)	(189)	(208)	**1 385**	1 532	422
(64)	(72)	(86)	**481**	601	189
—	—	—	**—**	38	—
$ (89)	$ (117)	$ (122)	**$ 904**	$ 893	$ 233
$ 14	$ 12	$ 8	**$ 1 681**	$ 1 203	$ 1 021
—	(3)	13	**10**	8	5
$ 14	$ 9	$ 21	**$ 1 691**	$ 1 211	$ 1 026
$ (53)	$ (102)	$ (84)	**$ 1 688**	$ 1 870	$ 964
$ 961	$ 1 562	$ 308	**$ 9 821**	$ 10 130	$ 8 661
$ 500	$ 1 150	$ 98	**$ 6 275**	$ 6 235	$ 5 707

Note 3 CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2001 the Company retroactively adopted the recommendations of the Canadian Institute of Chartered Accountants on accounting for earnings per share, the effect of which is not material.

Effective January 1, 2000 the Company adopted the recommendations of the Canadian Institute of Chartered Accountants on accounting for future income taxes and on accounting for employees' future benefits. The change in accounting policy for future income taxes has been adopted retroactively and retained earnings as at January 1, 2000 have been reduced by $175 million, while the liability for future income taxes has been increased by the same amount; prior periods have not been restated. The change in accounting policy for employees' future benefits has been adopted prospectively.

Note 4 TAXES AND CROWN ROYALTIES

In addition to the provision for income taxes and other taxes included in the consolidated statement of earnings, the following items have been collected or produced on behalf of governments and have been paid or are payable by the Company:

	2001	2000	1999
Provincial fuel and sales taxes	**$ 1 493**	$ 1 511	$ 1 464
Federal excise taxes	**852**	832	839
Goods and Services Tax collected	**913**	894	632
Crown royalties, paid and paid in kind	**428**	425	171
	$ 3 686	$ 3 662	$ 3 106

Note 5 GAINS ON DISPOSAL OF ASSETS

Investment and other income includes net gains on disposal of non-core assets of $49 million (2000 — $73 million;1999 — $3 million).

Note 6 OPERATING, MARKETING AND GENERAL EXPENSES

Operating, marketing and general expenses in 2000 includes a provision of $66 million for staff reductions and related building expenses. The provision decreased 2000 net earnings by $38 million.

Note 7 INCOME TAXES

The computation of the provision for income taxes, which requires adjustment to earnings before income taxes for non-taxable and non-deductible items, is as follows:

	2001	2000	1999
Earnings before income taxes	**$ 1 385**	$ 1 466	$ 422
Add (deduct):			
Non-deductible royalties and other payments to provincial governments, net	**413**	385	170
Resource allowance	**(476)**	(452)	(213)
Equity in earnings of affiliates	**(9)**	(10)	(11)
Non-taxable foreign exchange	**26**	22	5
Other	**(1)**	(18)	(2)
Non-deductible depreciation, depletion and amortization and disposals	**—**	—	70
Earnings as adjusted before income taxes	**$ 1 338**	$ 1 393	$ 441
Canadian Federal income tax rate	**38.0%**	38.0%	38.0%
Canadian Federal income tax on earnings as adjusted	**$ 508**	$ 529	$ 168
Large Corporations Tax	**15**	15	14
Provincial and other income taxes, net of federal abatement	**49**	62	28
Reduction of future income taxes due to provincial rate reductions	**(61)**	—	—
Income tax credits and other	**(30)**	(33)	(21)
Provision for income taxes	**$ 481**	$ 573	$ 189
Effective income tax rate on earnings before income taxes	**34.7%**	39.1%	44.8%

Future income taxes consists of the following future income tax liabilities (assets) relating to temporary differences for:

	2001	2000
Property, plant and equipment	**$ 1 325**	$ 1 372
Partnership income[1]	**397**	514
Inventories	**(78)**	(176)
Deferred credits and other liabilities	**(162)**	(166)
Deferred charges and other assets	**8**	(16)
Other	**(4)**	5
	$ 1 486	$ 1 533

1 Taxable income for certain upstream activities are generated by a partnership and the related current income taxes will be payable in the next year.

Complex income tax issues which involve interpretations of continually changing regulations are encountered in computing the provision for income taxes. Management believes that adequate provision has been made for all such outstanding issues.

Note 8 EARNINGS PER SHARE

The weighted average number of common shares outstanding used in the calculation of basic earnings per share and diluted earnings per share, assuming that all dilutive outstanding stock options were exercised, was:

	2001	2000	1999
Average shares outstanding (millions)			
Basic	**264.9**	272.3	271.5
Diluted	**267.4**	274.6	272.5

Note 9 ITEMS NOT AFFECTING CASH FLOW

	2001	2000	1999
Depreciation, depletion and amortization	**$ 568**	$ 584	$ 558
Future income taxes	**(47)**	210	42
Provision for future removal and site restoration costs	**17**	30	29
Amortization of unrealized foreign exchange losses	**46**	24	21
Gain on disposal of assets	**(49)**	(73)	(3)
Other	**4**	31	6
	$ 539	$ 806	$ 653

Note 10 DECREASE (INCREASE) IN OPERATING WORKING CAPITAL AND OTHER

	2001	2000	1999
Accounts receivable	**$ 531**	$ (348)	$ (258)
Inventories	**—**	46	(46)
Prepaid expenses	**5**	5	(10)
Accounts payable and accrued liabilities	**(403)**	254	244
Income taxes payable	**40**	122	(23)
Current portion of long-term liabilities and other	**(22)**	(37)	(62)
	$ 151	$ 42	$ (155)

Operating working capital is comprised of working capital other than cash and short-term investments and current portion of long-term debt.

The decrease (increase) in operating working capital and other consists of changes related to operating activities, investing activities and financing activities.

Note 11 CASH AND SHORT-TERM INVESTMENTS

Short-term investments are considered to be cash equivalents and are recorded at cost, which approximates market value.

	2001	2000
Cash	**$ 94**	$ 119
Less: outstanding cheques	**100**	151
	(6)	(32)
Short-term investments	**787**	1 447
	$ 781	$ 1 415

Cash payments for interest and income taxes were as follows:

	2001	2000	1999
Interest	**$ 158**	$ 154	$ 152
Income taxes	**483**	186	216

Note 12 INVENTORIES

	2001	2000
Crude oil, refined products and merchandise	**$ 377**	$ 370
Materials and supplies	**78**	85
	$ 455	$ 455

Note 13 PROPERTY, PLANT AND EQUIPMENT

	2001			2000			Capital Expenditures	
	Cost	Accumulated Depreciation, Depletion and Amortization	Net	Cost	Accumulated Depreciation, Depletion and Amortization	Net	2001	2000
Upstream								
Oil and gas								
Western Canada	**$ 3 593**	**$ 1 673**	**$ 1 920**	$ 3 474	$ 1 671	$ 1 803	**$ 404**	$ 341
Canada offshore	**2 362**	**326**	**2 036**	2 106	221	1 885	**257**	315
Foreign	**203**	**51**	**152**	100	45	55	**101**	18
Oil sands	**1 325**	**489**	**836**	1 128	537	591	**275**	94
Other	**25**	**16**	**9**	23	11	12	**2**	10
	7 508	**2 555**	**4 953**	6 831	2 485	4 346	**1 039**	778
Downstream								
Refining	**3 078**	**1 659**	**1 419**	2 851	1 574	1 277	**226**	119
Marketing and other	**1 803**	**758**	**1 045**	1 689	701	988	**157**	145
	4 881	**2 417**	**2 464**	4 540	2 275	2 265	**383**	264
Other property, plant and equipment	**432**	**389**	**43**	419	370	49	**14**	12
	$ 12 821	**$ 5 361**	**$ 7 460**	$ 11 790	$ 5 130	$ 6 660	**$ 1 436**	$ 1 054

Interest capitalized during 2001 amounted to $16 million (2000 — $12 million; 1999 — $11 million).

Capital expenditures and exploration expenses charged to earnings are classified as investing activities in the consolidated statement of cash flows.

Costs of $1 119 million (2000 — $912 million) relating to the Terra Nova Project and other non-producing Canada offshore projects are not currently being amortized.

The Company is party to an agreement for the time charter and operation of a vessel for the transportation of Canada offshore crude oil production. The time charter is for an initial term of ten years ending in 2007, is extendible at the Company's option for an additional 15 years, is accounted for as a capital lease (Note 15) and is included in Canada offshore at a net cost of $78 million (2000 — $82 million).

Note 14 DEFERRED CHARGES AND OTHER ASSETS

	2001	2000
Translation adjustment on long-term debt	**$ 187**	$ 130
Investments	**59**	65
Deferred pension funding	**49**	46
Deferred financing costs	**17**	18
Other	**40**	32
	$ 352	$ 291

Note 15 LONG-TERM DEBT

	Maturity	2001	2000
Debentures and notes			
9.25% unsecured debentures (U.S. $300 million)	2021	**$ 478**	$ 450
7.875% unsecured debentures (U.S. $275 million)	2026	**438**	413
7.00% unsecured debentures (U.S. $250 million)	2028	**398**	375
8.60% unsecured notes (U.S. $300 million)	2001	**—**	450
Capital lease (Note 13)[1]	2022	**87**	86
		1 401	1 774
Current portion		**(5)**	(454)
		$1 396	$1 320

1 The implicit rate of interest in the capital lease is 11.90%. The aggregate remaining repayment is $87 million (U.S. $55 million), including $5 million (U.S. $3 million) to $8 million (U.S. $5 million) in each of the next five years.

Interest on long-term debt was $134 million in 2001 (2000 — $138 million; 1999 — $137 million).

Note 16 DEFERRED CREDITS AND OTHER LIABILITIES

	2001	2000
Future removal and site restoration costs	**$ 216**	$ 214
Post-retirement benefits	**133**	126
Long-term liabilities	**132**	137
	$ 481	$ 477

Note 17 SHAREHOLDERS' EQUITY

	2001	2000
Common shares	**$ 1 228**	$ 1 238
Contributed surplus	**2 138**	2 456
Retained earnings	**1 695**	897
	$ 5 061	$ 4 591

The authorized share capital is comprised of an unlimited number of:

(a) Preferred shares issuable in series designated as Senior Preferred Shares
(b) Preferred shares issuable in series designated as Junior Preferred Shares
(c) Common shares

Prior to the Government of Canada passing legislation effective June 14, 2001, the common share capital was comprised of two classes of common equity: common shares which could be held only by residents of Canada and variable voting shares which could be held only by non-residents of Canada. The common shares and the variable voting shares differed only in their voting entitlements. The legislation removed the restrictions applying to variable voting shares, whereby they were converted to an equivalent number of common shares.

Note 17 SHAREHOLDERS' EQUITY (continued)

Changes in common shares were as follows:

	2001			2000		
	Shares	Amount	Contributed Surplus	Shares	Amount	Contributed Surplus
Balance at beginning of year	**269 807 215**	**$ 1 238**	**$ 2 456**	271 773 250	$ 1 223	$ 2 572
Issued for cash under employee stock option and share purchase plans	**1 813 581**	**34**	**—**	1 990 365	33	—
Purchased for cancellation	**(9 429 755)**	**(44)**	**(318)**	(3 956 400)	(18)	(116)
Balance at end of year	**262 191 041**	**$ 1 228**	**$ 2 138**	269 807 215	$ 1 238	$ 2 456

The Company repurchased common shares under a Normal Course Issuer Bid which commenced on November 1, 2000 and ended on October 31, 2001. During 2001, 9 429 755 shares (2000 — 3 956 400 shares) were purchased for a total cost of $362 million (2000 — $134 million). The excess of purchase cost over the carrying amount of the shares purchased is recorded as a reduction of contributed surplus.

Stock Option Plan

The Company maintains a stock option plan and may grant options to directors, officers and certain employees for up to 21 million common shares. The stock options have a maximum term of 10 years, vest over periods of up to five years and are exercisable at the market prices for the shares on the dates that the options were granted.

Changes in the number of outstanding stock options were as follows:

	2001		2000	
	Shares	Weighted-Average Exercise Price (dollars)	Shares	Weighted-Average Exercise Price (dollars)
Balance at beginning of year	**6 765 601**	**$ 20**	6 701 011	$ 18
Granted	**2 372 500**	**37**	1 984 800	23
Exercised	**(1 813 581)**	**18**	(1 832 160)	16
Cancelled	**(107 750)**	**27**	(88 050)	21
Balance at end of year	**7 216 770**	**26**	6 765 601	20

The following stock options were outstanding as at December 31, 2001:

Options Outstanding				Options Exercisable	
Number	Range of Exercise Prices (dollars)	Weighted-Average Life (years)	Weighted-Average Exercise Price (dollars)	Number	Weighted-Average Exercise Price (dollars)
124 720	$ 8 to 13	2.2	$ 10	124 720	$ 10
1 477 006	14 to 18	6.1	16	945 028	16
2 101 594	20 to 25	7.2	21	987 260	21
1 177 250	26 to 34	6.8	27	755 838	26
2 336 200	35 to 38	9.1	37	—	37
7 216 770	8 to 38	7.9	26	2 812 846	20

Note 18 EMPLOYEE FUTURE BENEFITS

The Company maintains pension plans with defined benefit and defined contribution provisions, and provides certain health care and life insurance benefits to its qualifying retirees. The actuarially determined cost of these benefits is accrued over the estimated service life of employees. The defined benefit provisions are generally based upon years of service and average salary during the final years of employment. Certain defined benefit options require employee contributions and the balance of the funding for the registered plans is provided by the Company, based upon the advice of an independent actuary. The defined contribution option provides for an annual contribution of 5% of each participating employee's pensionable earnings. Substantially all of the pension assets are invested in equity, fixed income and other marketable securities.

Benefit Plan Expense	Pension Plans			Other Post-Retirement Plans		
	2001	2000	1999	**2001**	2000	1999
(a) Defined benefit plans						
Employer current service cost	**$ 22**	$ 20	$ 18	**$ 2**	$ 3	$ 2
Interest cost	**70**	69	67	**11**	10	8
Expected return on plan assets	**(88)**	(83)	(90)	**—**	—	—
Amortization of transitional (asset) obligation	**(5)**	(5)	—	**2**	1	—
Amortization of past service costs (gains)	**—**	—	4	**—**	—	(1)
Amortization of net actuarial gains	**—**	—	(1)	**—**	—	(1)
	(1)	1	(2)	**15**	14	8
(b) Defined contribution plans	**7**	6	6			
Total expense	**$ 6**	$ 7	$ 4	**$ 15**	$ 14	$ 8
Benefit Plan Funding	**$ 9**	$ 6	$ 6	**$ 7**	$ 6	$ 5

Financial Status of Defined Benefit Plans	Pension Plans		Other Post-Retirement Plans	
	2001	2000	**2001**	2000
Fair value of plan assets	**$1 039**	$1 113	**$ —**	$ —
Accrued benefit obligation	**1 119**	1 047	**172**	160
Funded status — plan (deficit) surplus	**(80)**	66	**(172)**	(160)
Unamortized transitional (asset) obligation	**(44)**	(49)	**23**	25
Unamortized net actuarial losses	**173**	29	**16**	9
Accrued benefit asset (liability)	**$ 49**	$ 46	**$ (133)**	$ (126)
Reconciliation of Plan Assets				
Fair value of plan assets at beginning of year	**$1 113**	$1 052	**$ —**	$ —
Contributions	**9**	7	**—**	—
Benefits paid	**(60)**	(55)	**—**	—
Actual (loss) return on plan assets	**(17)**	115	**—**	—
Other	**(6)**	(6)	**—**	—
Fair value of plan assets at end of year	**$1 039**	$1 113	**$ —**	$ —
Reconciliation of Accrued Benefit Obligation				
Accrued benefit obligation at beginning of year	**$1 047**	$ 951	**$ 160**	$ 145
Current service cost	**22**	21	**2**	3
Interest cost	**70**	69	**11**	10
Benefits paid	**(60)**	(55)	**(7)**	(7)
Actuarial losses	**40**	61	**6**	9
Accrued benefit obligation at end of year	**$1 119**	$1 047	**$ 172**	$ 160

Note 18 EMPLOYEE FUTURE BENEFITS (continued)

Funded Status

The funded status includes the following amounts in respect of plans that are not fully funded:

	Pension Plans		Other Post-Retirement Plans	
	2001	2000	**2001**	2000
Accrued benefit obligation	**$ (161)**	$ (67)	**$ (172)**	$ (160)
Fair value of plan assets	**67**	—	**—**	—
Plan deficit	**$ (94)**	$ (67)	**$ (172)**	$ (160)

Defined Benefit Plan Assumptions

	2001	2000	1999
Year-end obligation discount rate	**6.50%**	6.75%	8.00%
Pension expense discount rate	**6.75%**	7.25%	8.00%
Long-term rate of return on plan assets	**8.00%**	8.00%	8.00%
Rate of compensation increase, excluding merit increases	**3.00%**	2.50%[1]	2.00%[1]
Annual increase in the per capita cost of other post-retirement benefits	**6.20%**[2]	6.20%	4.80%

1 3.0% in 2001 and thereafter.
2 4.2% in 2005 and thereafter.

Note 19 RELATED PARTY TRANSACTIONS

Transactions with the Government of Canada (which holds 19% of the Company's issued shares at December 31, 2001), its agencies and other related parties, are in the normal course of business and are therefore on the same terms as those accorded to non-related parties.

Note 20 FAIR VALUE OF FINANCIAL INSTRUMENTS

As at December 31, 2001 the fair value, the related method of determination and the carrying value of the Company's financial instruments were as follows:

Current Assets/Current Liabilities

The fair value of financial instruments included in current assets and current liabilities, excluding the current portion of long-term debt, approximates the carrying amount of these instruments due to their short maturity.

Long-Term Debt

The fair value of long-term debt is based on publicly quoted market values.

Derivative Instruments

The fair value of derivative instruments, which is based on quotes provided by brokers, represents an approximation of amounts that would be received or paid to counterparties to settle these instruments prior to maturity. The Company plans to hold all derivative instruments outstanding at December 31, 2001 to maturity.

	Carrying Amount	Fair Value
Financial instruments included in current assets and current liabilities	$ 381	$ 381
Long-term debt[1]	(1 401)	(1 538)
Derivative instruments	—	(11)

1 Excludes translation adjustment of $187 million (Note 14).

Note 21 DERIVATIVE INSTRUMENTS

The Company is exposed to market risks resulting from fluctuations in foreign exchange, interest rates and commodity prices in the course of its normal business operations. The Company actively monitors its exposure to market fluctuations and may use derivative instruments to manage these risks, as it considers appropriate. These derivative instruments are entered into solely for hedging purposes.

Crude Oil
The downstream business segment may use forward contracts and options to reduce exposure to margin fluctuations, including margins on fixed price product sales, and short-term price fluctuations on the purchase of foreign and domestic crude oil.

Natural Gas
The downstream business segment has entered into forward contracts to purchase natural gas fuel related to fixed price product sales.

Currency
The downstream business segment has reduced its exposure to exchange rate movements between the Canadian dollar and the euro related to fixed price product sales by entering into forward contracts.

The Company's outstanding contracts for derivative instruments and related unrealized losses at December 31, 2001 were as follows:

	Quantity	Average Price	Unrealized Loss	Maturity
Crude Oil (millions of barrels)				
Crude oil purchase	6.7	$ 36.12[1]	$ 10	2002/2003
Natural Gas (billions of cubic feet)				
Natural gas purchase	0.5	5.08[1]	1	2002
Currency (millions of euro)				
Forwards purchase	3.0	1.4195[2]	—	2002
			$ 11	

1 Canadian dollars per barrel or per thousand cubic feet, as applicable.
2 Weighted-average euro forward contract rate.

Derivative instruments involve a degree of credit risk which the Company controls through the establishment of credit policies and limits and the selection of financially sound counterparties. Market risk relating to changes in value or settlement cost of the Company's derivative instruments is essentially offset by gains or losses on the hedged positions.

Note 22 COMMITMENTS AND CONTINGENT LIABILITIES

(a) The Company has leased property and equipment under various long-term operating leases for periods up to 2013. The minimum annual rentals for non-cancellable operating leases are estimated at $87 million in 2002, $71 million in 2003, $59 million in 2004, $50 million in 2005, $45 million in 2006 and $42 million per year thereafter until 2013.

(b) The Company is involved in litigation and claims associated with normal operations. Management is of the opinion that any resulting settlements would not materially affect the financial position of the Company.

Note 23 GENERALLY ACCEPTED ACCOUNTING PRINCIPLES IN THE UNITED STATES

The Company's consolidated financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in Canada, which differ in some respects from those applicable in the United States. The following are the significant differences in accounting principles as they pertain to the accompanying consolidated financial statements:

(a) Effective January 1, 2000 the Company adopted the recommendations of the Canadian Institute of Chartered Accountants on accounting for future income taxes and changed from the deferral method to the liability method (Note 3). This liability method differs from United States GAAP due to the application of transitional provisions and the accounting for certain Canadian income tax credits and allowances.

(b) The Company defers unrealized gains and losses on translation of long-term debt payable in foreign currencies for amortization over the remaining term of the debt. Under United States GAAP gains or losses on the translation of long-term debt payable in foreign currencies would be credited or charged to earnings with no deferral.

(c) United States GAAP requires that interest be capitalized as part of the cost of certain assets while they are being prepared for their intended use. The Company capitalizes interest attributable to the construction of major new facilities and does not capitalize interest on all assets which would require interest capitalization under United States GAAP.

(d) In prior years the Company transferred amounts from contributed surplus to the accumulated deficit. Under United States GAAP these transfers would not have occurred.

(e) United States GAAP utilizes the concept of comprehensive income which includes certain items not included in net earnings. There is no similar concept under Canadian GAAP.

(f) Under United States GAAP the Company would be required to adopt the Statement of Financial Accounting Standard ("SFAS") No. 133, Accounting for Derivative Instruments and Hedging Activities, effective January 1, 2001. SFAS No. 133 establishes accounting and reporting standards requiring that all derivative instruments be recorded in the balance sheet as either an asset or a liability measured at fair value and requires that changes in the fair value be recognized currently in earnings unless specific hedge accounting criteria are met. The hedge accounting treatment allows unrealized gains and losses to be deferred in comprehensive income until such time as the forecasted transaction occurs.

The application of United States GAAP would have the following effects on earnings as reported:

	2001	2000	1999
Net earnings as reported in the consolidated statement of earnings	**$ 904**	$ 893	$ 233
Adjustments, net of applicable income taxes			
Foreign currency translation	**(58)**	(34)	85
Capitalization of interest and related amortization	**31**	14	11
Accounting for income taxes	**(29)**	(35)	3
Other	**(1)**	1	(1)
Net earnings, as adjusted	**$ 847**	$ 839	$ 331
Earnings per share, as adjusted — basic	**$ 3.20**	$ 3.08	$ 1.22
Earnings per share, as adjusted — diluted	**$ 3.17**	$ 3.06	$ 1.22
Comprehensive income			
Net earnings, as adjusted	**$ 847**	$ 839	$ 331
Unrealized loss on financial derivatives	**(7)**	—	—
	$ 840	$ 839	$ 331

Note 23 GENERALLY ACCEPTED ACCOUNTING PRINCIPLES IN THE UNITED STATES (continued)

The application of United States GAAP would have the following effects on the consolidated balance sheets as reported:

	As Reported	Increase (Decrease)	United States GAAP
December 31, 2001			
Current assets	**$ 2 009**	**$ —**	**$ 2 009**
Property, plant and equipment, net	**7 460**	**577**	**8 037**
Deferred charges and other assets	**352**	**(194)**	**158**
Current liabilities	**1 397**	**11**	**1 408**
Long-term debt	**1 396**	**—**	**1 396**
Deferred credits and other liabilities	**481**	**—**	**481**
Future income taxes	**1 486**	**260**	**1 746**
Common shares	**1 228**	**—**	**1 228**
Contributed surplus	**2 138**	**1 122**	**3 260**
Retained earnings	**1 695**	**(1 003)**	**692**
Accumulated other comprehensive income (loss)	**—**	**(7)**	**(7)**
December 31, 2000			
Current assets	$ 3 179	$ —	$ 3 179
Property, plant and equipment, net	6 660	551	7 211
Deferred charges and other assets	291	(137)	154
Current liabilities	2 209	—	2 209
Long-term debt	1 320	—	1 320
Deferred credits and other liabilities	477	—	477
Future income taxes	1 533	238	1 771
Common shares	1 238	—	1 238
Contributed surplus	2 456	1 122	3 578
Retained earnings (deficit)	897	(946)	(49)

Note 24 SUBSEQUENT EVENT

On January 29, 2002 the Company announced that it has agreed to acquire the international oil and gas operations of Veba Oil & Gas GmbH ("Veba") from Veba and BP plc for a cash consideration of the current equivalent of $3.2 billion, subject to rights of first refusal, closing adjustments and transaction costs. The acquisition, which is expected to close in stages from May to September 2002 due to rights of first refusal affecting certain assets and obtaining approvals from governments, will be financed by funds from committed credit facilities with certain banks.

SUPPLEMENTAL INFORMATION

Net Proved Developed and Undeveloped Reserves Before Royalties [1,2]

	Crude Oil and Field Natural Gas Liquids (millions of barrels)						Natural Gas [11] (billions of cubic feet)
	Western Canada	International [4,5,6]	East Coast [7]	Synthetic Crude Oil [9]	Bitumen [10]	Total	Total
Beginning of year 2000	110	13	34	319	—	476	2 481
Revisions of previous estimates	21	(2)	—	10	—	29	(40)
Sale of reserves in place	(75)	(10)	—	—	—	(85)	(180)
Purchase of reserves in place	—	—	—	—	—	—	—
Discoveries, extensions and improved recovery	6	6	15	—	—	27	341
Production	(8)	(5)	(11)	(9)	—	(33)	(271)
End of year 2000	54	2	38	320	—	414	2 331
Revisions of previous estimates	1	—	—	—	—	1	8
Sale of reserves in place	(2)	—	—	—	—	(2)	(120)
Purchase of reserves in place	—	10	—	—	—	10	9
Discoveries, extensions and improved recovery	7	—	15	—	33	55	261
Production	(6)	(1)	(11)	(10)	—	(28)	(261)
End of year 2001	**54**	**11**	**42**	**310**	**33**	**450**	**2 228**

Net Probable Reserves Before Royalties [1,3]

	Crude Oil and Field Natural Gas Liquids (millions of barrels)						Natural Gas [11] (billions of cubic feet)
	Western Canada	International [4,5,6]	East Coast [8]	Synthetic Crude Oil [9]	Bitumen [8]	Total	Total
End of year 2000	23	23	211	134	247	638	1 078
Revisions of previous estimates	(2)	—	—	—	—	(2)	(194)
Sale of reserves in place	—	—	—	—	—	—	(10)
Purchase of reserves in place	—	20	—	—	—	20	—
Discoveries, extensions and improved recovery	4	—	(6)	—	(32)	(34)	230
End of year 2001	**25**	**43**	**205**	**134**	**215**	**622**	**1 104**

1 Net proved developed and undeveloped and probable reserves before royalties are Petro-Canada's working interest in reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. No reserve quantities have been included to reflect royalty interests Petro-Canada has in various properties.

2 Proved reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves that are expected to be recovered from existing wells or facilities. Proved undeveloped reserves are proved reserves which are not recoverable from existing wells or facilities, but which are expected to be recovered through additional development drilling or through the upgrading of existing or additional new facilities.

3 Unproved reserves are based on geological and/or engineering data similar to that used in estimates of proved reserves, but technical, contractual, economic or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves. Probable reserves are less certain than proved reserves and can be estimated with a degree of certainty sufficient to indicate they are more likely to be recovered than not.

4 Year-end 2001 international proved reserves are in Algeria (1.2 million barrels) and Libya (9.9 million barrels). Year-end 2001 international probable reserves are in Algeria (22.7 million barrels and 220.5 billion cubic feet) and Libya (20.0 million barrels).

5 After deduction of a 20 per cent royalty, Petro-Canada receives crude oil to recover costs incurred on behalf of Petro-Canada and SONATRACH, the Algerian state oil company. The remaining production is shared between Petro-Canada and SONATRACH, varying with the level of production. The total share accruing to Petro-Canada cannot exceed 49 per cent of gross production volumes.

6 Production in Libya is subject to an Exploration and Production Sharing Agreement (EPSA) between Petro-Canada and the National Oil Corporation of Libya (NOC). Under the terms of the EPSA, Petro-Canada and its predecessors pay 100 per cent of exploration costs, 50 per cent of development costs and 25 per cent of operating costs. Crude oil production is split between NOC (75 per cent) and Petro-Canada (25 per cent) until the cumulative value of crude oil received by Petro-Canada equals Petro-Canada's net cumulative capital and operating expenditures. After costs have been recovered, the remaining production is shared between NOC and Petro-Canada, varying with the level of production and a payback ratio. Petro-Canada's Libyan reserves in the Before Royalty tables above comprise 50 per cent of estimated gross field reserves.

7 Proved reserves at Hibernia and Terra Nova are based on primary recovery for drilled fault blocks and undrilled fault blocks which lie between drilled fault blocks plus incremental recovery in fault blocks showing response to water or gas injection.

8 Probable reserves at Hibernia, Terra Nova and MacKay River are based on estimates of the ultimate recovery from the current depletion plans for the properties, less volumes produced or included in proved reserves.

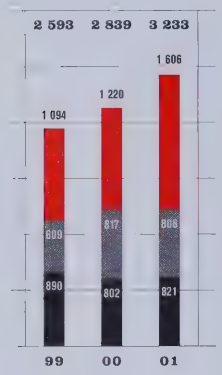
9 Proved and probable reserves of synthetic crude oil are based on high geological certainty and application of proven or piloted technology. For proved reserves, drill hole spacing is less than 500 metres and appropriate co-owner and regulatory approvals are in place. For probable reserves, drill hole spacing is less than 1 000 metres, appropriate co-owner approvals are in place and regulatory approvals are being sought.

10 Proved reserves at MacKay River are based on conservative estimates of recovery from existing producer-injector well pairs.

11 Natural gas reserves reflect marketable (not raw) quantities.

RESERVES INVENTORY

Our large reserves inventory provides a strong base for future growth.



- Proved reserves *(millions of barrels of oil equivalent)*
- Probable reserves *(millions of barrels of oil equivalent)*
- Possible reserves *(millions of barrels of oil equivalent)*

(Caution should be exercised in aggregating proved, probable and possible reserves. There is a 90% probability that actual reserves will equal or exceed proved reserves, a 50% probability that actual reserves will equal or exceed the sum of proved and probable reserves and a 10% probability that actual reserves will equal or exceed the sum of proved, probable and possible reserves).

– 1999 reserves have been restated to reflect a change in the gas-to-oil conversion factor, from 10:1 to 6:1.

Principal Reserve and Production Locations

Crude Oil [1] Fields	Proved Reserves Before Royalties at December 31, 2001 (millions of barrels)	Per Cent of Total Proved Oil Reserves	Average 2001 Daily Production Before Royalties (thousands of barrels)	Per Cent of Total 2001 Daily Oil Production
Syncrude, Alberta	310.2	73.4	26.8	40.6
MacKay River, Alberta	32.5	7.7	—	—
Hibernia, Offshore Newfoundland	26.1	6.2	29.6	44.7
Terra Nova, Offshore Newfoundland	16.2	3.8	—	—
Ferrier, Alberta	14.1	3.3	3.6	5.4
En Naga, Libya	9.9	2.4	—	—
Willesden Green, Alberta	5.5	1.3	1.8	2.8
Ricinus/Bearberry area, Alberta	3.1	0.7	0.8	1.2
Brazeau, Alberta	1.6	0.4	0.6	0.9
Gilby/Wilson Creek, Alberta	1.4	0.3	0.5	0.8
Other	1.8	0.5	2.5	3.6
Total	**422.4**	**100**	**66.2**	**100**

Natural Gas [1] Fields	Proved Reserves Before Royalties at December 31, 2001 (billions of cubic feet)	Per Cent of Total Proved Gas Reserves	Average 2001 Daily Production Before Royalties (millions of cubic feet)	Per Cent of Total 2001 Daily Gas Production
Wildcat Hills area, Alberta	579.8	26.0	138.6	19.4
Hanlan area, Alberta	290.3	13.0	102.5	14.3
Jedney/Beg/Bubbles, British Columbia	244.7	11.0	41.8	5.8
Ricinus/Bearberry area, Alberta	171.4	7.7	106.8	14.9
Medicine Hat, Alberta	138.7	6.2	29.4	4.1
Laprise area, British Columbia	128.1	5.7	39.1	5.5
Gilby/Wilson Creek, Alberta	100.7	4.5	33.0	4.6
Alderson, Alberta	81.6	3.7	21.7	3.0
Ferrier, Alberta	77.1	3.5	22.5	3.2
Clarke Lake, British Columbia	68.2	3.1	33.0	4.6
Other	347.7	15.6	146.0	20.6
Total	**2 228.3**	**100**	**714.4**	**100**

1 Does not include natural gas liquids.

Oil and Gas Landholdings (Gross [1]/Net [2]) (millions of acres)

	Developed [3]		Undeveloped [4]		Total	
	Gross	Net	Gross	Net	Gross	Net
Offshore Canada						
East Coast [5]	0.1	—	6.3	2.4	6.4	2.4
Other	—	—	7.5	6.2	7.5	6.2
Mainland Canada [6]	2.0	1.0	4.1	2.5	6.1	3.5
Oil Sands	—	—	0.8	0.3	0.8	0.3
Alaska	—	—	0.3	0.3	0.3	0.3
International	—	—	5.7	5.7	5.7	5.7
Total	**2.1**	**1.0**	**24.7**	**17.4**	**26.8**	**18.4**

1 Includes interests of others.
2 Excludes interests of others.
3 Areas capable of production.
4 Areas with rights to explore.
5 Includes parcels acquired at the 2001 Newfoundland and Labrador and Nova Scotia land sales, for which licences were issued in the first quarter of 2002. The Flemish Pass parcel acquired at the Newfoundland and Labrador land sale covers acreage of 0.54 million gross acres (0.18 million net). The parcel acquired at the Nova Scotia sale covers acreage of 0.366 million gross acres (0.183 million net).
6 Includes Mackenzie Delta.

QUARTERLY FINANCIAL AND STOCK TRADING INFORMATION

(unaudited, stated in millions of dollars unless otherwise indicated)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
				2001				2000
Revenue								
Operating	**$2 476**	**$2 277**	**$2 072**	**$1 757**	$2 086	$2 133	$2 421	$2 732
Investment and other income	**75**	**21**	**(3)**	**15**	(153)	120	13	169
	2 551	**2 298**	**2 069**	**1 772**	1 933	2 253	2 434	2 901
Expenses								
Crude oil and product purchases	**1 249**	**1 239**	**1 233**	**966**	1 245	1 236	1 471	1 585
Operating, marketing and general [1]	**408**	**391**	**408**	**463**	438	380	380	421
Exploration	**111**	**38**	**37**	**59**	30	32	38	71
Depreciation, depletion and amortization	**139**	**148**	**134**	**147**	161	133	127	163
Interest	**38**	**34**	**36**	**27**	34	36	36	38
	1 945	**1 850**	**1 848**	**1 662**	1 908	1 817	2 052	2 278
Earnings Before Income Taxes	**606**	**448**	**221**	**110**	25	436	382	623
Provision for Income Taxes	**248**	**122**	**72**	**39**	6	177	153	237
Net Earnings	**$ 358**	**$ 326**	**$ 149**	**$ 71**	$ 19	$ 259	$ 229	$ 386
Cash Flow	**$ 629**	**$ 454**	**$ 298**	**$ 307**	$ 308	$ 428	$ 450	$ 684
Segmented Earnings								
Earnings from operations								
Upstream	**$ 256**	**$ 230**	**$ 125**	**$ 52**	$ 126	$ 149	$ 185	$ 244
Downstream	**91**	**111**	**50**	**48**	61	72	74	66
Shared Services	**(20)**	**(15)**	**(25)**	**(29)**	(39)	(28)	(27)	(23)
Reorganization costs	**—**	**—**	**—**	**—**	(33)	—	—	(5)
	327	**326**	**150**	**71**	115	193	232	282
Gain (loss) on sale of assets	**31**	**—**	**(1)**	**—**	(96)	66	(3)	104
Net earnings	**$ 358**	**$ 326**	**$ 149**	**$ 71**	$ 19	$ 259	$ 229	$ 386
Share Information (dollars per share)								
Earnings								
— Basic	**1.33**	**1.23**	**0.57**	**0.27**	0.07	0.95	0.84	1.42
— Diluted	**1.32**	**1.21**	**0.56**	**0.27**	0.07	0.94	0.83	1.40
Cash Flow	**2.34**	**1.71**	**1.13**	**1.17**	1.13	1.57	1.65	2.52
Dividends per share	**0.10**	**0.10**	**0.10**	**0.10**	0.10	0.10	0.10	0.10
Share price [2]								
— High	**38.60**	**43.65**	**42.01**	**43.50**	25.30	31.15	35.80	38.45
— Low	**33.50**	**35.05**	**35.33**	**35.09**	19.00	22.60	26.40	30.80
— Close (end of period)	**35.44**	**36.02**	**38.97**	**39.31**	24.15	27.65	33.50	38.15
Shares traded (millions) [3]	**59.4**	**65.3**	**37.9**	**49.4**	57.0	57.9	54.9	55.0

1 Operating, marketing and general expenses for 2000 includes a provision of $66 million before income taxes for reorganization costs.

2 Share prices are for trading on the Toronto Stock Exchange.

3 Total shares traded on the Toronto and New York stock exchanges.

FIVE-YEAR FINANCIAL AND OPERATING SUMMARY [1]

(stated in millions of dollars, unless otherwise indicated)

	2001	2000	1999	1998	1997
Consolidated					
Revenue	**$8 690**	$9 521	$6 147	$5 016	$6 096
Expenses	**7 305**	8 055	5 725	4 797	5 460
Provision for income taxes	**481**	573	189	124	330
Net Earnings	**$ 904**	$ 893	$ 233	$ 95	$ 306
Cash flow	**1 688**	1 870	964	830	1 263
Total assets	**9 821**	10 130	8 661	8 398	8 338
Average capital employed	**6 255**	5 884	5 630	5 536	5 406
Operating return on capital employed (per cent) (in 2000 and 1998, before reorganization costs)	**15.2**	16.0	5.6	3.6	6.9
Return on capital employed (per cent)	**15.7**	16.6	5.6	3.0	6.8
Debt	**1 401**	1 774	1 711	1 829	1 741
Debt to debt plus equity (per cent)	**21.7**	27.9	29.5	31.7	30.7
Debt to cash flow (times)	**0.8**	0.9	1.8	2.2	1.4
Expenditures on property, plant and equipment and exploration	**1 681**	1 203	1 021	1 116	1 049
Employees (number at year end) [2]	**4 178**	4 024	4 417	4 620	5 749
Shareholders' Data					
Weighted average number of common shares outstanding (millions) [3]	**264.9**	272.3	271.5	271.2	270.9
Shares outstanding at year end (millions)	**262.2**	269.8	271.8	271.3	271.0
Publicly held shares at year end (millions)	**212.8**	220.4	222.4	221.9	221.6
Share prices (dollars) [4]					
— at year end	**39.31**	38.15	20.45	16.25	26.00
— range during the year	**33.50-43.65**	19.00-38.45	15.35-25.10	14.55-26.95	18.90-29.85
Shares traded (millions) [5]	**212.0**	224.8	184.7	244.7	271.1
Book value per share (dollars)	**19.30**	17.02	15.02	14.51	14.47

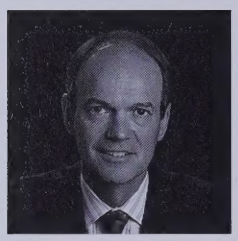
1 Certain reclassifications have been made to the figures previously reported to reflect subsequent changes in reporting presentation.
2 Numbers prior to 1998 include employees of ICG Propane Inc., a subsidiary that was sold in 1998.
3 Includes 49.4 million shares held as an investment by the Government of Canada.
4 Year-end prices and ranges are from the Toronto Stock Exchange.
5 Total shares traded on the Toronto and New York stock exchanges.

	2001	2000	1999	1998	1997
Upstream Sector					
Earnings from operations	**$ 663**	$ 704	$ 243	$ 29	$ 188
Gain (loss) on sale of assets	**29**	72	6	30	(2)
Net earnings	**$ 692**	$ 776	$ 249	$ 59	$ 186
Cash flow	**1 152**	1 538	885	516	900
Expenditures on property, plant and equipment and exploration	**1 284**	927	793	818	805
Daily production (net, before royalties)					
Crude oil and field liquids (thousands of barrels)	**77.4**	89.2	95.3	101.1	95.1
Natural gas (excluding injectants, millions of cubic feet)	**714**	738	719	722	760
Average sale price					
Crude oil and field liquids (per barrel)[1]	**37.30**	41.45	24.58	17.72	25.79
Natural gas (per thousand cubic feet)[1,2]	**6.00**	4.75	2.59	1.96	1.85
Proved reserves (net, before royalties)					
Crude oil and field liquids (millions of barrels)	**450**	414	476	476	432
Natural gas (trillions of cubic feet)	**2.2**	2.3	2.5	2.5	2.5
Oil and gas landholdings (gross/net) (millions of acres)	**26.8/18.4**	22.7/15.3	22.0/14.9	19.2/13.3	17.3/12.0
Wells drilled (gross/net)					
Oil	**30/16**	41/21	51/13	76/33	127/65
Natural gas	**354/229**	234/135	164/95	188/83	145/82
Oil Sands	**50/50**	0/0	0/0	0/0	0/0
Dry	**27/16**	23/6	26/8	23/9	34/21
Total	**461/311**	298/162	241/116	287/125	306/168
Downstream Sector					
Earnings from operations	**$ 300**	$ 273	$ 115	$ 204	$ 225
Gain (loss) on sale of assets	**1**	(1)	(9)	(35)	(6)
Net earnings	**$ 301**	$ 272	$ 106	$ 169	$ 219
Cash flow	**589**	434	163	420	415
Expenditures on property, plant and equipment	**383**	264	220	276	215
Petroleum product sales (thousands of cubic metres per day)	**54.5**	55.4	51.2	49.1	48.5
Retail outlets at year end	**1 566**	1 618	1 658	1 709	1 780
Refinery crude capacity at year end (thousands of cubic metres per day)	**49.8**	49.8	49.0	49.0	45.4
Average refinery utilization (per cent)	**96**	101	100	95	103

1 After the impact of hedging activities.
2 Before deduction of British Columbia gathering and processing charges.

EXECUTIVE LEADERSHIP TEAM

As of January 31, 2002



Ron Brenneman
Chief Executive Officer



Norm McIntyre
President



Boris Jackman
Executive Vice-President (Downstream)



Harry Roberts
Senior Vice-President and Chief Financial Officer

The following executives were appointed to the Executive Leadership Team on February 13, 2002: Kathy Sendall, Senior Vice-President, Western Canada; Brant Sangster, Senior Vice-President, Oil Sands; and Gordon Carrick, Vice-President, East Coast.

BOARD OF DIRECTORS

Ronald A. Brenneman, a resident of Calgary, has been chief executive officer and a director of Petro-Canada since January 2000. Mr. Brenneman has more than 30 years of industry experience in upstream, downstream and corporate roles, and has held senior executive positions with a major Canadian and international organization. He is a director of the Bank of Nova Scotia.

Angus A. Bruneau, O.C., a resident of St. John's, has been a director of Petro-Canada since 1996. Dr. Bruneau is chairman of the board of Fortis Inc. He is a director of Inco Limited, the SNC-Lavalin Group Inc., Canada Life Assurance Company, and North Atlantic Pipeline Partners, L.P. He is a member of the Natural Sciences and Engineering Research Council and the Canadian Foundation for Innovation, and serves on the board of the Nature Conservancy of Canada and the Council for Canadian Unity.

Gail Cook-Bennett [1], a resident of Toronto, has been a director of Petro-Canada since 1991. Dr. Cook-Bennett is chairperson of the Canada Pension Plan Investment Board. She is a director of Enbridge Consumers Gas Company, Groupe Transcontinental G.T.C. Ltee., and Manulife Financial Corporation.

John F. Cordeau, a resident of Calgary, has been a director of Petro-Canada since 1994. Mr. Cordeau is a partner and litigation department head at Bennett Jones LLP, a Canadian-based law firm with offices in Calgary, Edmonton and Toronto. He is a director of a number of private companies.

Purdy Crawford, a resident of Toronto, has been a director of Petro-Canada since 1995. Mr. Crawford is chairman of AT&T Canada Corp. and past chairman of Imasco Limited. He is a director of Camco Inc., Canadian National Railway Company, Emera Inc., Inco Limited, Maple Leaf Foods Inc., Seamark Asset Management Ltd., and Foot Locker Inc. He also serves as counsel to Osler, Hoskin & Harcourt.

Claude Fontaine [1], a resident of Montreal, has been a director of Petro-Canada since 1987. Mr. Fontaine is a senior partner with Ogilvy Renault. He is a director of Domtar Inc., Optimum General Inc., the Montreal Heart Institute Research Fund and the Council for Canadian Unity.

Thomas E. Kierans, O.C., a resident of Toronto, has been a director of Petro-Canada since 1991, and served as chairman of the board from 1996 until January 2000. Mr. Kierans is chairman of the Canadian Institute for Advanced Research, and the Toronto International Leadership Centre for Financial Sector Supervision. He is a director of Manulife Financial Corporation, IPSCO Inc., Inmet Mining Corp., BCE Inc., Teleglobe Inc. and Telesat Canada. He is advisor to Corporation Lazard Canada.

Brian F. MacNeill [1], a resident of Calgary and a director of Petro-Canada since 1995, was appointed chairman in May 2000. Mr. MacNeill is past president and CEO of Enbridge Inc. He is a director of Enbridge Inc., the Toronto-Dominion Bank, Dofasco Inc., Western Oil Sands Inc., West Fraser Timber Co. Ltd., TELUS Corporation, Sears Canada Inc., and Veritas DGC Inc. He is a member of the Alberta and Ontario Institutes of Chartered Accountants and the Financial Executives Institute. He is a Fellow of the Canadian Institute of Chartered Accountants, and Chair of the Board of Governors of the University of Calgary.

Paul Melnuk [1], a resident of St. Louis, Missouri, joined Petro-Canada's Board of Directors in July 2000. Mr. Melnuk is Managing Partner of FTL Capital Partners. He is a past president and CEO of Barrick Gold Corporation, Clark USA, Inc. and Bracknell Corporation. He is a member of the Young Presidents' Organization, St. Louis chapter.

Guylaine Saucier [1], C.M., a resident of Montreal, has been a director of Petro-Canada since 1991. Ms. Saucier was chairperson of the Joint Committee on Corporate Governance and past chairperson of the Canadian Broadcasting Corporation and the Canadian Institute of Chartered Accountants. She is a director of the International Federation of Accountants, the Bank of Montreal, Nortel Networks Corporation, AXA Assurances Inc., and Tembec Inc.

William W. Siebens, a resident of Calgary, has been a director of Petro-Canada since 1986. Mr. Siebens is president and CEO of Candor Investments Ltd., and chairman of Freehold Royalty Trust. He is a director of The Fraser Institute.

1 Audit, Finance and Risk Committee member

INVESTOR INFORMATION

Outstanding Shares
At December 31, 2001, Petro-Canada's public float was 212.8 million shares.

Transfer Agent and Registrar
In Canada:
CIBC Mellon Trust Company

In the United States:
Mellon Investor Services, LLC

Telephone toll free: 1-800-387-0825
Fax: (416) 643-5660 or
(416) 643-5661
E-mail: inquiries@cibcmellon.com
Web site: www.cibcmellon.com

Duplicate Reports
Shareholders with more than one unregistered account may receive duplicate materials. To eliminate duplicate mailings, contact the transfer agent and registrar.

Annual and Special Meeting
The annual and special meeting of shareholders will be held at 11:00 a.m. local time Tuesday, April 30, 2002
The Palliser Hotel, Crystal Ballroom
133-9th Avenue S.W.
Calgary, Alberta

Stock Exchange Listings and Symbols
Toronto: PCA
New York: PCZ

Dividends
Petro-Canada's Board of Directors has adopted a policy of paying quarterly dividends of $0.10 ($0.40 per annum) per common share. The Board regularly reviews the dividend policy in light of the company's financial position, its financing requirements for growth, and other factors.

On Our Web Site...
The following documents are available on Petro-Canada's Web site at www.petro-canada.ca

- Statistical Supplement
- Annual Information Form
- Quarterly Reports
- Proxy Circular
- Petro-Canada's Code of Business Conduct
- Report to the Community

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Fax: (403) 296-3030
Web site: www.petro-canada.ca

We'd Like Your Feedback
We invite your comments on our low-cost annual report format. Please e-mail your comments to: sbraunga@petro-canada.ca

GLOSSARY OF FINANCIAL TERMS AND RATIOS

Terms
BARREL OF OIL EQUIVALENT: Natural gas production (excluding injectants) is converted using 6 000 cubic feet of gas for one barrel of oil.

CAPITAL EMPLOYED: Total of shareholders' equity and debt, less related foreign currency translation adjustment.

CASH FLOW: Cash flow from operations before changes in non-cash working capital items.

DEBT: Long-term debt including current portion.

EARNINGS FROM OPERATIONS: Earnings before gains (losses) on asset sales.

Ratios
RETURN ON CAPITAL EMPLOYED: Net earnings plus after-tax interest expense divided by average capital employed. Measures net earnings relative to the asset base.

OPERATING RETURN ON CAPITAL EMPLOYED: Earnings from operations plus after-tax interest expense divided by average capital employed. Measures operating earnings relative to the asset base.

RETURN ON EQUITY: Net earnings divided by average shareholders' equity. Measures the return earned by shareholders on their investment in the Company.

CURRENT RATIO: Current assets divided by current liabilities. Reflects the Company's short-term liquidity and its ability to pay short-term debts.

DEBT TO CASH FLOW: Debt divided by cash flow. Indicates the Company's ability to discharge its outstanding debt.

DEBT TO DEBT PLUS EQUITY: Debt divided by debt plus equity. Indicates the relative amount of debt in the Company's capital structure. Measures financial strength.

INTEREST COVERAGE: Measures the Company's ability to cover interest charges on debt.

Earnings basis: Earnings before interest expense and provision for income taxes divided by interest expense plus capitalized interest.

EBITDAX basis: Earnings before interest expense, income taxes, depreciation, depletion and amortization and exploration expenses divided by interest expense plus capitalized interest.

Cash flow basis: Cash flow before interest expense and current income taxes divided by interest expense plus capitalized interest.

Conversion Factors
To conform with common usage, imperial units of measurement are used in this report to describe exploration and production, while metric units are used for refining and marketing. Dollars are Canadian unless otherwise stated.

1 cubic metre (liquids) = 6.29 barrels
1 cubic metre (natural gas) = 35.49 cubic feet
1 litre = 0.22 imperial gallon
1 hectare = 2.47 acres
1 cubic metre = 1 000 litres

DESIGN: Bhandari & Plater Inc. *COVER PHOTOGRAPH:* Dennis Minty *PAGE 2 AND 3 PHOTOGRAPHY* (from left) Hibernia Management and Development Company Ltd., Dan Sorensen, Joëlle Opelik, Albert Normandin *EXECUTIVE PHOTOGRAPHY:* Bernard Bohn
This annual report was printed on paper that is acid-free and recyclable. Inks are based on linseed oil and contain no heavy metals. The printing process was alcohol-free. Volatile organic compounds associated with printing were reduced by 50 to 75 per cent from the levels that would have been produced using traditional inks and processes.

A HIGHLY CAPABLE COMPANY

Petro-Canada is focused and disciplined, with the financial and human capabilty to execute our ambitious strategy.

BUILDING ON OUR ESTABLISHED TRACK RECORD

The Terra Nova offshore oil development is on stream, and bitumen production will begin at MacKay River by year-end 2002.

FINANCIAL STRENGTH AND FLEXIBILITY

Strong 2001 results and disciplined cost management give Petro-Canada the ability to invest in growth and seize opportunities to build value.

LOOKING AHEAD WITH CONFIDENCE

We have solid strategies to grow shareholder value in each of our core businesses, with reserves already identified for development over the next decade.

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www.petro-canada.ca

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